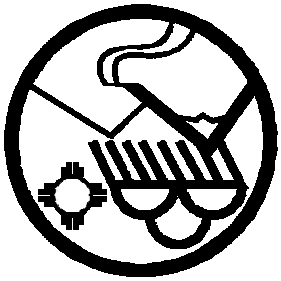
Mail Application To:		Application No. _____
New Mexico Environment Department Air Quality Bureau New Source Review Unit 2048 Galisteo Santa Fe, NM 87505 Phone (505) 827-1494 http://www.nmenv.state.nm.us		AIRS No. _____-_____-_____ *For NMED use only*

Air Quality Permit Application And Notice Of Intent
Universal (General) to Construct or Modify

Acknowledgement: **X** I acknowledge that a pre-application meeting is available to me upon request

X Permit filing fee enclosed, Check No.: _____

Part I – General Information

I-A: Company Information

1	Company name: **University of California for the U.S. Department of Energy**		Date application notarized: **2/28/05**
2	Facility name: **Los Alamos National Laboratory**		SIC code (4 digits): **9711**
3	Company mailing address: **Meteorology and Air Quality Group, P.O. Box 1663, MS J978, Los Alamos, NM 87545**		
4	Contact person: **Jean Dewart**		Title: **Group Leader**
5	Phone No: **505-665-0239**	Fax No: **505-665-8858**	E-mail: **dewart@lanl.gov**

I-B: Current Facility Status

1	This application is for (check one): □ New Facility, **X** Modification to an existing facility, or □ Revision	
2	Has this facility already been constructed? **X** Yes □No	If yes, is it currently operating in New Mexico? **X** Yes □No
3	Is the plant currently shut down? □Yes **X** No	If yes, give month and year of shut down (MM/YY): **N/A**
4	Was this facility constructed before 1972 and operated since 1972? **X** Yes □No	
5	Does this facility have an operating permit under 20 NMAC 2.70? **X** Yes □No	If yes, the permit No. is: **P-100**
6	Has this facility been issued a No Permit Required (NPR)? **X** Yes □No	If yes, the NPR number is: **2195A, 2195L**
7	Has this facility been issued a Notice of Intent (NOI)? **X** Yes □No	If yes, the NOI Number is: **2597**
8	Does this facility have a construction permit (20 NMAC 2.72, Section 200.A or 200.B) **X** Yes □No	
•	If yes, the permit No. is: **2195, 2195B–M1, 2195F, 2195H**	
9	Has this facility been issued a general permit (GCP-1, GCP-2,…)? **X**Yes □No	If yes, the registration No. is: **GCP3-2195G**
10	Is this a "major source" under the PSD rules? □Yes **X** No □Unsure.	Is this a "major source" under Title V (20 NMAC
•	2.70)? **X** Yes □No □Unsure.	Is this a major modification under the PSD rules (20 NMAC 2.74)? □Yes **X** No □Unsure.
11	If *Yes* or *Unsure* to any of the questions in question No. 10, contact the AQB to see if a pre-application meeting is required.	

Table I-B: Current Facility Status (continued)

12	What is the facility's maximum input capacity, specify units (reference here and list capacities in Attachment L if more room is required)			
•	Current[1]	Hourly: **N/A`**	Daily: **N/A`**	Annually: **N/A`**
•	Proposed[2]	Hourly: **55 MMBtu/hr heat input**	Daily: **1,320 MMBtu/24 hr heat input**	Annually: **481,800 MMBtu/year heat input**
13	What is the facility's maximum production rate, specify units (reference here and list capacities in Attachment L, if more room is required)			
•	Current[1]	Hourly: **N/A**	Daily: **N/A**	Annually: **N/A**
•	Proposed[2]	Hourly: **44 MMBtu/hr heat output**	Daily: **1,056 MMBtu/24 hr heat output**	Annually: **385,440 MMBtu/year heat output**

[1]**Neither LANL or the existing CMR facility has a maximum input capacity or production rate.**
[2]**For the CMR Replacement Project, the values listed are for total boiler capacity to be located within the Utility Building.**

Table I-C: Facility Location Information

1	Section: **22**	Range: **6E**	Township: **19N**	County: **Los Alamos**	Elevation (ft): **7,218**
2	UTM Zone: □12 or **X**13	UTMH (record to one tenth of a km): **382.5**		UTMV (record to one tenth of a km): **3,969.2**	
OR	Latitude (deg., min., sec.):		Longitude (deg., min., sec.):		
3a	Name and zip code of nearest New Mexico town: **Los Alamos 87544**				
3b	Distance and Direction from nearest New Mexico town: **3 miles south of Los Alamos**				
4	Detailed Driving Instructions from nearest NM town (attach a road map if necessary): The facility is **3** (distance) miles **south** (direction) of **Los Alamos** (nearest town) **within Technical Area 55 on Pajarito Road.**				
5	Status of land at facility (check one): □Private □Indian/Pueblo **X** Government **(Department of Energy)**				
6	Name of nearest Class I area to the facility (see Figure 1.0): **Bandelier Wilderness Area**				
7	Shortest distance from facility boundary to the boundary of the nearest Class I area (record to one tenth of a km): **5.2**				

Table I-D: Proposed Operating Schedule (Note: the operating schedule (D1, D2) shall become a condition of the permit)

1	Facility **maximum** operating ($\frac{\text{hours}}{\text{day}}$): **24**	($\frac{\text{days}}{\text{week}}$): **7**	($\frac{\text{weeks}}{\text{year}}$): **52**	($\frac{\text{hours}}{\text{year}}$): **8760**			
2	Facility's maximum daily operating schedule (if less than 24 $\frac{\text{hours}}{\text{day}}$)? Start: **N/A**		□AM □PM	End: **N/A**		AM PM	
3	Month and year of anticipated start of construction: **RLUOB: August 2005 CAT I Facility: April 2007**						
4	Month and year of anticipated construction completion: **RLUOB: August 2007 CAT I Facility: June 2011**						
5	Month and year of anticipated startup of new or modified facility: **RLUOB: August 2007 CAT I Facility: June 2011**						
6	Will this facility operate at this site for more than one year? **X** Yes □No						

Table I-E: Other

1	Is this application in response to a Notice of Violation (NOV)? □Yes **X** No	
•	If yes, NOV date: **N/A**	NOV Tracking No: **N/A**
2	Is air quality dispersion modeling being submitted with this application? **X** Yes □No	
3	Does this facility require an "Air Toxics" permit under 20 NMAC 2.72, Part IV, Tables A and/or B in Part V? □Yes **X** No	
4	Will this facility be a source of federal Hazardous Air Pollutants? **X** Yes □No **(Not a major source)**	
•	If yes, list applicable subparts in 40 CFR 61 & 63: **40 CFR Part 61 – Subparts C and H**	

Part II – Required Attachments

The following Attachments are required, please label each accordingly. A complete application shall include:

Attachment A A process flow sheet and/or block diagram indicating the individual equipment, all emission points and types of control applied to those points. Numbering system should cross reference with Attachment B.

Attachment B A plot plan drawn to scale, showing emissions points, structures, tanks, and fences of property owned, leased, or under direct control of the applicant.

Attachment C All calculations used to determine both the hourly and annual controlled and uncontrolled emission rates. Reference where emission factors were obtained. If identical units are being permitted and will be subject to the same operating conditions, submit calculations for only one unit and a note specifying what other units the calculations represent.

Attachment D Information Used to Determine Emissions

- If manufacturer data are used, include specifications for emissions units and control equipment.
- If test data are used, include a copy of the complete test report. If the test data are for an emissions unit other than the one being permitted, the emission units must be identical. Test data may not be used if any difference in operating conditions of the unit being permitted and the unit represented in the test report significantly effect emission rates.
- If the most current copy of AP-42 is used, reference the section and date located at the bottom of the page. Include a copy of the page containing the emissions factors, and clearly mark the factors used in the calculations.
- If an older version of AP-42 is used, include a complete copy of the section.
- If an EPA document or other material is referenced, include a complete copy.
- Fuel specifications sheet.
- If computer models are used to estimate emissions, include an input summary (if available) and a detailed report, and a disk containing the input file(s) used to run the model. For tank-flashing emissions, include a discussion of the method used to estimate tank-flashing emissions, relative thresholds (i.e., permit or major source (NSPS, PSD or Title V)), accuracy of the model, the input and output from simulation models and software, all calculations, documentation of any assumptions used, descriptions of sampling methods and conditions, copies of any lab sample analysis.

Attachment E A map such as a 7.5 minute topographic quadrangle showing the exact location of the source. The map shall also include the following:

The UTM or Longitudinal coordinate system on both axes	An indicator showing which direction is north
A minimum radius around the plant of 5km (3.1 miles)	The nearest occupied structure(s)
Topographic features of the area	Access and haul roads
The name of the map	Facility property boundaries
A scale	The area which will be restricted to public access

Attachment F Proof of public notice; Include a copy of the certified letter receipts, a list of the places where the public notice has been posted, and: (see guidance document)

a sample of the letters sent to land owners	a sample and verification of the local postings
a sample of the letters sent to municipalities	a copy of the display ad and its affidavit of publication
a copy of the announcement sent to a local radio station	a copy of the classified ad and its affidavit of publication

Attachment G A written description of the routine operations of the facility. Include a description of how each piece of equipment will be operated, how controls will be used, and the fate of both the products and waste generated. For modifications and/or revisions, explain how the changes will affect the existing process.

Attachment H A PSD applicability determination for all sources. For PSD major sources applying for a significant permit revision, use the procedures for Determining the Net Emissions Change at a Source as specified by Table A-5 (Page A.45) of the EPA New Source Review Workshop Manual to determine if the revision is subject to PSD review.

Attachment I A discussion demonstrating compliance with each applicable state & federal regulation. If there is a state or federal regulation for your facility's source category that does not apply to your facility, explain why. For example 40 CFR 60 Subpart OOO (crushers), 40 CFR 63 Subpart HHH (HAPs), or 20 NMAC 2.74 (PSD major sources).

Attachment J A preliminary operational plan defining the measures to be taken to mitigate source emissions during malfunction, startup, or shutdown.

Attachment K An air quality dispersion modeling demonstration (if applicable) as outlined in the Air Quality Bureau's Dispersion Modeling Guidelines.

Attachment L Other relevant information. Use this attachment to clarify any part in the application that you think needs explaining. Reference the section, table, column, and/or field.

Submit the original signed and notarized copy of the application package and;

1) One working copy for department use, and
2) One copy if air dispersion modeling is included (include disks with input and output files), and
3) One copy if public notice was required, and
4) If subject to PSD review under 20 NMAC 2.74 (PSD) one copy for US EPA, one copy for each federal land manager affected (NPS, USFS, FWS, USDI), and one copy for each affected regulatory agency other than the Air Quality Bureau.

Part III – Production and Control Equipment

Table III-A: Regulated Equipment (Unit and stack numbering must correspond throughout the application package.)
Note: If applying for a NOI under 20 NMAC 2.73, equipment exemptions under 2.72, 202 do not apply, and all equipment should be listed here.

Unit No.	Manufacturer / Date of Manufacture /Reconstruction. (MM/DD/YY)	Model No. / Serial No.	Type (Source Description)	Capacity (Specify Units)	For Each Piece of Equipment, Check One	Applicable State Reg. (s) 20 NMAC 2.X, …	Replacing Unit No.
B-1 B-2 B-3 B-4 B-5	**TBD (To be Determined)** **TBD**	**TBD** **TBD**	**Boilers**	**11 MMBtu/hr EACH**	Existing (unchanged) To be Removed **x** New/Additional Replacement Unit To be Modified To be Replaced	**20.2.3 NMAC 20.2.7 NMAC 20.2.61 NMAC 20.2.70 NMAC 20.2.73 NMAC 20.2.77 NMAC**	
M-1	**N/A** **N/A**	**N/A** **N/A**	**Metallographic Sample Preparation**	**N/A**	Existing (unchanged) To be Removed **x** New/Additional Replacement Unit To be Modified To be Replaced	**20.2.70 NMAC 20.2.73 NMAC 20.2.78 NMAC**	
	Note: This application is for the specified activity and not for specific equipment.						
CU-1	**N/A** **N/A**	**N/A** **N/A**	**Chemical Usage**	**N/A**	Existing (unchanged) To be Removed **x** New/Additional Replacement Unit To be Modified To be Replaced	**20.2.3 NMAC 20.2.70 NMAC 20.2.73 NMAC**	
	Note: This application is for the specified activity and not for specific equipment.						
					Existing (unchanged) To be Removed New/Additional Replacement Unit To be Modified To be Replaced		
					Existing (unchanged) To be Removed New/Additional Replacement Unit To be Modified To be Replaced		
					Existing (unchanged) To be Removed New/Additional Replacement Unit To be Modified To be Replaced		

Table III-B: 20 NMAC 2.72, 202.B Exempted Equipment **(If exempt under 20 NMAC 2.72, 202.B.5, list emission rates in Table IV-A.)**

(Unit and stack numbering must correspond throughout the application package.)

Note: This table is applicable only if applying for a 20 NMAC 2.72 permit. Exemptions under 20 NMAC 2.72, 202 do not apply to facilities requesting a NOI under 20 NMAC 2.73. See application form instructions and Exemptions Procedure for instructions on this form.

Unit No.	Manufacturer / Date of Mfg. (MM/DD/YY)	Model No. / Serial No.	Type (Source Description)	Capacity (Specify Units)	For Each Piece of Equipment, Check One	Site Specific 20 NMAC 2.72.202 Exemption (e.g. 2.72.202.B.5)	Other Required Information
DG-1	TBD / TBD	TBD / TBD	Standby diesel generator	1.25 MW	Existing (unchanged) / **X** New/Additional / To be Modified; To be Removed / Replacement Unit / To be Replaced	2.72.202.B.3	N/A
DG-2	TBD / TBD	TBD / TBD	Standby diesel generator	0.5 MW	Existing (unchanged) / **X** New/Additional / To be Modified; To be Removed / Replacement Unit / To be Replaced	2.72.202.B.3	N/A
DG-3	TBD / TBD	TBD / TBD	Standby diesel generator	1.25 MW	Existing (unchanged) / **X** New/Additional / To be Modified; To be Removed / Replacement Unit / To be Replaced	2.72.202.B.3	N/A
DG-4	TBD / TBD	TBD / TBD	Standby diesel generator	1.25 MW	Existing (unchanged) / **X** New/Additional / To be Modified; To be Removed / Replacement Unit / To be Replaced	2.72.202.B.3	N/A
DG-5	TBD / TBD	TBD / TBD	Standby diesel generator	1.25 MW	Existing (unchanged) / **X** New/Additional / To be Modified; To be Removed / Replacement Unit / To be Replaced	2.72.202.B.3	N/A
					Existing (unchanged) / New/Additional / To be Modified; To be Removed / Replacement Unit / To be Replaced		
					Existing (unchanged) / New/Additional / To be Modified; To be Removed / Replacement Unit / To be Replaced		
					Existing (unchanged) / New/Additional / To be Modified; To be Removed / Replacement Unit / To be Replaced		
					Existing (unchanged) / New/Additional / To be Modified; To be Removed / Replacement Unit / To be Replaced		
					Existing (unchanged) / New/Additional / To be Modified; To be Removed / Replacement Unit / To be Replaced		

Table III-C: Emissions Control Equipment (Additional information)
(Unit and stack numbering must correspond throughout the application package.)

Unit No.	Control Equipment Description	Controlled Pollutant(s)	Controlling Emissions for Unit(s) No.	% Control by Weight	Estimation Method
B-1 B-2 B-3 B-4 B-5	**Low NOx Burner**	**NOx**	**Boiler 1 (B-1) Boiler 2 (B-2) Boiler 3 (B-3) Boiler 4 (B-4) Boiler 5 (B-5)**	**50% (approximate)**	**AP-42**
M-1	**HEPA Filters (first at glovebox, then 3 in series)**	**Beryllium**	**M-1**	**99.95% (installed)**	**Vendor Specification**

Only list control equipment for TAPs if the TAP's PER is over its respective threshold as listed in 20 NMAC 2.72 Subpart V Tables A and B

Part IV - Emission Calculations

Table IV-A: Unit Emissions Rates List Toxic Air Pollutants (TAPs) In Table IV-C
(Unit and stack numbering must correspond throughout the application package.) Include tank-flashing emissions estimates.

	Potential emission rate (PER)[1]							Potential to emit (PTE)[2]						
Unit No.	**TSP lb/hr** / **ton/yr**	**PM10 lb/hr** / **ton/yr**	**NOx lb/hr** / **ton/yr**	**CO lb/hr** / **ton/yr**	**VOC lb/hr** / **ton/yr**	**SOx lb/hr** / **ton/yr**	**Lead H_2S lb/hr** / **ton/yr**	**TSP lb/hr** / **ton/yr**	**PM10 lb/hr** / **ton/yr**	**NOx lb/hr** / **ton/yr**	**CO lb/hr** / **ton/yr**	**VOC lb/hr** / **ton/yr**	**SOx lb/hr** / **ton/yr**	**Lead H_2S lb/hr** / **ton/yr**
B-1	**0.1 gas**	**0.1 gas**	**0.7 gas**	**1.1 gas**	**0.1 gas**	**0.1 gas**		**0.1 gas**	**0.1 gas**	**0.7 gas**	**1.1 gas**	**0.1 gas**	**0.1 gas**	
B-2	**0.3 oil**	**0.2 oil**	**1.6 oil**	**0.5 oil**	**0.02 oil**	**5.8 oil**	**Negligible**	**0.3 oil**	**0.2 oil**	**1.6 oil**	**0.5 oil**	**0.02 oil**	**5.8 oil**	**Negligible**
B-3														
B-4														
B-5														
each														
B-1														
B-2														
B-3														
B-4														
B-5														
total	**5.8**	**4.0**	**35.2**	**24.0**	**1.3**	**126.6**	**Negligible**	**2.3**	**2.1**	**17.2**	**24.9**	**1.3**	**11.8**	**Negligible**
	Note: Ton per year values for boilers are the higher from gas vrs. oil usage assuming 8,760 hours of operation and no fuel restriction.							**Note: Ton per year values are the total from both gas and oil usage with an annual fuel oil restriction of 289,100 gallons.**						
M-1	**Negligible**	**Negligible**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**Negligible**	**Negligible**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**
	Negligible	**Negligible**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**Negligible**	**Negligible**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**
CU-1	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**
	N/A	**N/A**	**N/A**	**N/A**	**7.5**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**7.5**	**N/A**	**N/A**
Totals →	**0.5 gas**	**0.5 gas**	**3.5 gas**	**5.5 gas**	**0.5 gas**	**0.5 gas**		**0.5 gas**	**0.5 gas**	**3.5 gas**	**5.5 gas**	**0.5 gas**	**0.5 gas**	
	1.5 oil	**1.0 oil**	**8.0 oil**	**2.5 oil**	**0.1 oil**	**29.0 oil**	**Negligible**	**1.5 oil**	**1.0 oil**	**8.0 oil**	**2.5 oil**	**0.1 oil**	**29.0 oil**	**Negligible**
	5.8	**4.0**	**35.2**	**24.0**	**8.8**	**126.6**	**Negligible**	**2.3**	**2.1**	**17.2**	**24.9**	**8.8**	**11.8**	**Negligible**

[1] (PER) or "Potential Emission Rate" means the emission rate of a source at its maximum capacity to emit a regulated air contaminant under its physical and operational design, provided any physical or operational limitation on the capacity of the source to emit a regulated air contaminant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored or processed, shall be treated as part of its physical and operational design only if the limitation or the effect it would have on emissions is enforceable by the Department pursuant to the Air Quality Control Act or the federal Act.

[2] (PTE) or "Potential to emit" means the maximum capacity of a stationary source to emit a regulated air contaminant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a regulated air contaminant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitations or the effect it would have on emissions is federally enforceable. Secondary emissions do not count in determining the potential to emit of a stationary source. 20 NMAC 2.72, 300.E PTE does include reductions in emissions due to federally enforceable limits.

Table IV-B: Stack Exit and Fugitive[1] Emission (PTE) Rates for Pollutants and Stack Exit Conditions List Toxic Air Pollutants (TAPs) and Hazardous Air Pollutants (HAPs) In Table IV-C (Unit and stack numbering must correspond throughout the application package.) Include tank-flashing emissions estimates.

		Stack Exit Emission Rates for Criteria Pollutants							Stack Exit Conditions (Not Applicable for Fugitives)				
		TSP lb/hr	PM10 lb/hr	NOx lb/hr	CO lb/hr	VOC lb/hr	SOx lb/hr	Lead H_2S lb/hr	Orientation (H=Horizontal V=Vertical)	Height Above Ground (ft)	Flow Rate (acfm)	Moisture by Volume (%)	Inside Diameter or
Stack No.	Unit No.(s) from Table III-A	ton/yr	ton/yr	ton/yr	ton/yr	ton/yr	ton/yr	ton/yr	Rain Caps (Yes or No)	Temp. (F)	(dscfm)	Velocity (ft/sec)	L ×W (ft)
UB-1	B-1 B-2 B-3 B-4 B-5	0.5 gas 1.5 oil	0.5 gas 1.0 oil	3.5 gas 8.0 oil	5.5 gas 2.5 oil	0.5 gas 0.1 oil	0.5 gas 29.0 oil	Negligible	H	33	6,110	TBD	
		2.3	2.1	17.2	24.9	1.3	11.8	Negligible	No	280	4,295	20.7	2.5
CAT I-1	M-1	Negligible	Negligible	N/A	N/A	N/A	N/A	N/A	H	53	186,817	TBD	
		Negligible	Negligible	N/A	N/A	N/A	N/A	N/A	No	75	138,000	61.9	8
N/A	CU-1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
		N/A	N/A	N/A	N/A	7.5	N/A	N/A	N/A	N/A	N/A	N/A	N/A
		Note: VOC emissions from laboratory scale usage of chemicals are not emitted from any single stack at the facility.											
Totals →		0.5 gas 1.5 oil	0.5 gas 1.0 oil	3.5 gas 8.0 oil	5.5 gas 2.5 oil	0.5 gas 0.1 oil	0.5 gas 29.0 oil	Negligible					
		2.3	2.1	17.2	24.9	8.8	11.8	Negligible					

[1] List all fugitives that are associated with the normal, routine, or non-emergency operation of the facility.

Table IV-C: Stack Exit Emission Rates for HAPs and TAPs (Describe Stack Exit Conditions in Table IV-B)
(Unit and stack numbering must correspond throughout the application package.) Include tank-flashing emissions estimates

Stack No.	Unit No.(s)	Specify the name of the HAP or TAP as it appears in Section 112. (b) of the 1990 CAAA or 20 NMAC 2.72 Subpart V in the space provided below.							
		HAP ☐ TAP ☐	HAP ☐ TAP ☐	HAP ☐ TAP ☐	HAP ☐ TAP ☐	HAP ☐ TAP ☐	HAP ☐ TAP ☐	HAP ☐ TAP ☐	HAP ☐ TAP ☐
		lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr
		ton/yr	ton/yr	ton/yr	ton/yr	ton/yr	ton/yr	ton/yr	ton/yr
UB-1	B-1, B-2, B-3, B-4, B-5	**Note: Emission estimates are shown in Attachment C for HAPs from the combustion of natural gas and oil. Total annual HAP emissions are estimated to be 0.45 tpy from natural gas usage and 0.009 tpy from fuel oil. There are no AP-42 emission factors for TAPs, but emissions from controlled combustion in boilers are negligible.**							
CAT I-1	M-1	**Note: Maximum beryllium (HAP) emission rates are 0.5 grams per 24-hours and 3.0 grams per year. Emission estimates are shown in Attachment C.**							
N/A	CU-1	**Note: Emission estimates are shown in Attachment C for HAPs from laboratory scale usage of chemicals. Total annual HAP emissions are estimated to be 0.35 tpy. TAP emission estimates are not available but should be negligible.**							
TOTAL →									

Only list TAPs that have a PER greater than the threshold emission rate listed in 20 NMAC 2.72 Subpart V, Tables A and B

Part V – Fuel

Table V-A: Fuel Characteristics and Usage (Unit and stack numbering must correspond throughout the application package.)						
Unit No.	Fuel Type (No. 2 Diesel, Natural Gas, Coal, …)	Specify Units				
		Lower Heating Value	Hourly Usage	Annual Usage	% Sulfur	% Ash
B-1	Natural Gas	914.3 Btu/scf (LHV) 1012.9 Btu/scf (HHV)	0.0109 MM scf	95.5 MM scf	<0.01	N/A
B-2	Natural Gas	Same	0.0109 MM scf	95.5 MM scf	<0.01	N/A
B-3	Natural Gas	Same	0.0109 MM scf	95.5 MM scf	<0.01	N/A
B-4	Natural Gas	Same	0.0109 MM scf	95.5 MM scf	<0.01	N/A
B-5	Natural Gas	Same	0.0109 MM scf	95.5 MM scf	<0.01	N/A
B-1	No. 2 Fuel Oil	137,000 Btu/gal	0.0803 M gal	289.1 M gal total for all 5 boilers	0.5	Negligible
B-2	No. 2 Fuel Oil	137,000 Btu/gal	0.0803 M gal		0.5	Negligible
B-3	No. 2 Fuel Oil	137,000 Btu/gal	0.0803 M gal		0.5	Negligible
B-4	No. 2 Fuel Oil	137,000 Btu/gal	0.0803 M gal		0.5	Negligible
B-5	No. 2 Fuel Oil	137,000 Btu/gal	0.0803 M gal		0.5	Negligible

Part VI – Material Storage and Handling

Table VI-A: Liquid Storage Data[1] (Use additional sheets if necessary.) . (Unit and stack numbering must correspond throughout the application package.)
Include appropriate tank-flashing modeling input data. Use an addendum to this table for unlisted data categories

Tank No.	Material Name	Composition	Liquid Density (lb/gal)	Vapor Molecular Weight (lb/(lb*mol))	Average Storage Conditions		Max Storage Conditions	
					Temp-erature (°F)	True Vapor Pressure (psia)	Temp-erature (°F)	True Vapor Pressure (psia)
UB-T1	No. 2 Fuel Oil	No. 2 Fuel Oil	7.4	130	59	<0.02	71	<0.02
DG-1-T1	No. 2 Fuel Oil	No. 2 Fuel Oil	7.4	130	59	<0.02	71	<0.02
DG-2-T2	No. 2 Fuel Oil	No. 2 Fuel Oil	7.4	130	59	<0.02	71	<0.02
DG-3-T3	No. 2 Fuel Oil	No. 2 Fuel Oil	7.4	130	59	<0.02	71	<0.02
DG-4-T4	No. 2 Fuel Oil	No. 2 Fuel Oil	7.4	130	59	<0.02	71	<0.02
DG-5-T5	No. 2 Fuel Oil	No. 2 Fuel Oil	7.4	130	59	<0.02	71	<0.02

[1] If tank is to be used for storage of different materials, list all the materials, run the newest version of TANKS on each and use the material with the highest emission rate to determine PER and PTE .

Table VI-B: Liquid Storage Tank Data (Use additional sheets if necessary.) (Unit and stack numbering must correspond throughout the application package.)
Include appropriate tank-flashing modeling input data. Use an addendum to this table for unlisted data categories.

Tank No.	Date Installed/ Modified (MM/YY)	Materials Stored	Roof Type (Table VI-C)	Seal Type (Table VI-C)	Capacity[1] (bbl)	Capacity[1] (M^3)	Diameter (M)	Vapor Space (M)	Color (Table VI-C) Roof	Color (Table VI-C) Shell	Paint Condition (Table VI-C)	Annual Through-put (gal/yr)	Turn-overs per year
UB-T1	TBD	No. 2 Fuel Oil	TBD	TBD	119	18.9	TBD	TBD	TBD	TBD	Good	5,000	1
DG-1-T1	TBD	No. 2 Fuel Oil	TBD	TBD	11.9	1.9	TBD	TBD	TBD	TBD	Good	500	1
DG-2-T2	TBD	No. 2 Fuel Oil	TBD	TBD	59.5	9.5	TBD	TBD	TBD	TBD	Good	2,500	1
DG-3-T3	TBD	No. 2 Fuel Oil	TBD	TBD	59.5	9.5	TBD	TBD	TBD	TBD	Good	2,500	1
DG-4-T4	TBD	No. 2 Fuel Oil	TBD	TBD	59.5	9.5	TBD	TBD	TBD	TBD	Good	2,500	1
DG-5-T5	TBD	No. 2 Fuel Oil	TBD	TBD	59.5	9.5	TBD	TBD	TBD	TBD	Good	2,500	1
Note: Fuel oil is a standby fuel for the tanks listed associated with the Utility Building boilers and diesel generators. The estimated turnovers per year are intended to include normal testing and maintenance on the units only. Air emissions from tanks storing fuel oil are negligible.													

Table VI-C: Liquid Storage Tank Data Codes

Roof Type	Seal Type, Welded Tank Seal Type		Seal Type, Riveted Tank Seal Type		Roof, Shell Color	Paint Cond.
FX, Fixed Roof	1, Mechanical Shoe Seal	2, Liquid-mounted resilient seal	3, Vapor-mounted resilient seal	4, Seal Type	WH, White	Good
IF, Internal Floating Roof	A, Primary only	A, Primary only	A, Primary only	A, Mechanical shoe, primary only	AS, Aluminum (specular)	Poor
EF, External Floating Roof	B, Shoe-mounted secondary	B, Weather shield	B, Weather shield	B, Shoe mounted secondary	AD, Aluminum (diffuse)	
P, Pressure	C, Rim-mounted secondary	C, Rim-mounted secondary	C, Rim-mounted secondary	C, Rim-mounted secondary	LG, Light Gray	
					MG, Medium Gray	
					BL, Black	
					OT, Other	

[1] 0.159 M^3 = 42.0 gal = 1.00 bbl

Rev 7/18/02

Table VI-D: Materials Processed and Produced (Use additional sheets if necessary.)							
Material Processed				**Material Produced**			
Description	**Chemical Composition**	**Phase[1]**	**Quantity (specify units)**	**Description**	**Chemical Composition**	**Phase[1]**	**Quantity (specify units)**
N/A – Fuel combustion by boilers and research and development activities.							

[1]G =Gas, L = Liquid, or S = Solid

Part VII – Emissions Measurement

Table VII-A: Continuous Emissions Measurement (CEM) Equipment (Use additional sheets if necessary.)
(Unit and stack numbering must correspond throughout the application package.)

Stack No.	Pollutant(s)	Manufacturer	Model No.	Serial No.	Sample Frequency	Averaging Time	Range	Sensitivity	Accuracy
No Continuous Emissions Measurement (CEMs) equipment required or proposed.									

Note: If CEM data will be used as part of a federally enforceable permit condition, or used to satisfy the requirements of a state or federal regulation, include a copy of the CEM's manufacturer specification sheet in Attachment D.

Table VII-B: Parametric Emissions Measurement Equipment (Use additional sheets if necessary.)

(Unit and stack numbering must correspond throughout the application package.)

Unit No.	Parameter/ Pollutant Measured	Location of Measurement	Unit of Measure	Acceptable Range	Frequency of Maintenance	Nature of Maintenance	Method of Recording	Averaging Time
B-1 B-2 B-3 B-4 B-5	**Fuel Usage**	**Fuel inlet to boiler**	**TBD**	**TBD**	**TBD**	**TBD**	**Fuel Monitor**	**TBD**
M-1	**Pressure Drop**	**Across HEPA filtration system**	**TBD**	**TBD**	**TBD**	**TBD**	**Differential Pressure Gauge**	**TBD**

Part VIII – Certification

Company Name: **University of California for the U.S. Department of Energy**

We, **Jean Dewart and Timothy Nelson** , hereby certify that the information and data submitted in this application are true and as accurate as possible, to the best of my knowledge and professional expertise and experience.

Signed this ____ day of _____, _____, upon my oath or affirmation, before a notary of the State of **New Mexico**.

_____ _____
Signature Date

Jean Dewart **Group Leader – ENV-MAQ**
Printed Name Title

_____ _____
Signature Date

Timothy Nelson **Project Director - PADNWP**
Printed Name Title

Scribed and sworn before me on this ____ day of _____, _____.

My authorization as a notary of the State of **New Mexico** expires on the _____ day of _____, _____.

_____ _____
Notary's Signature Date

Delilah Baldonado
Notary's Printed Name

Rev 7/18/02

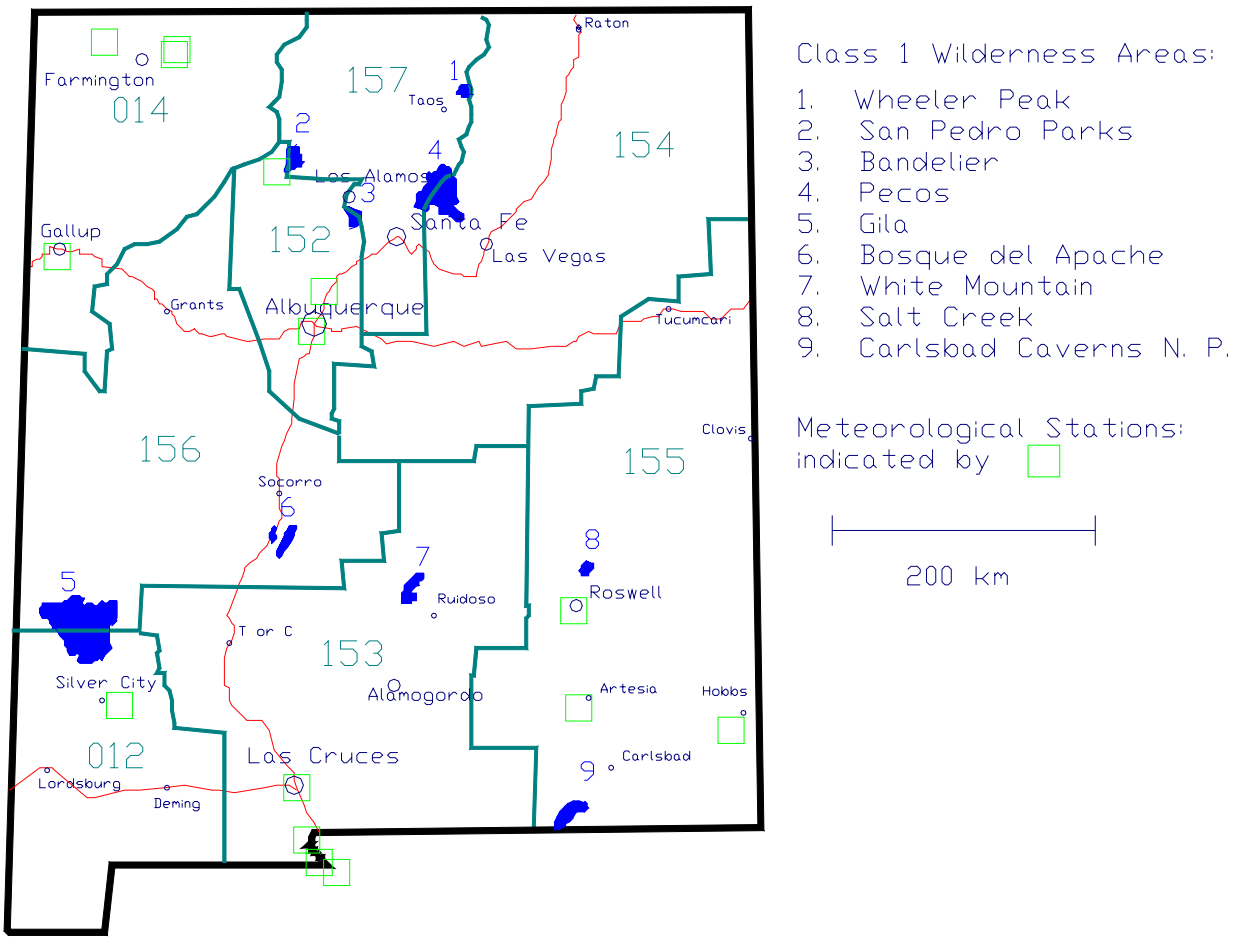


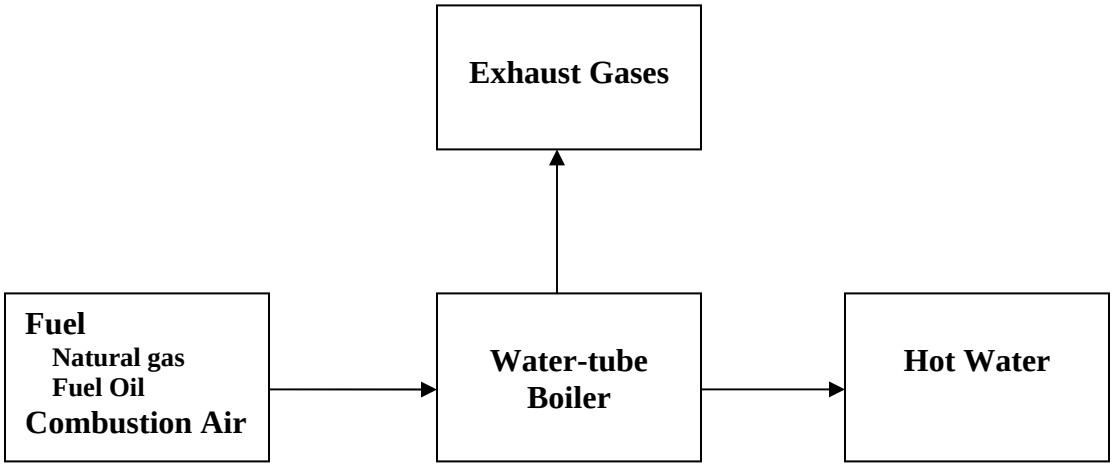
Figure 1.0

Rev 7/18/02

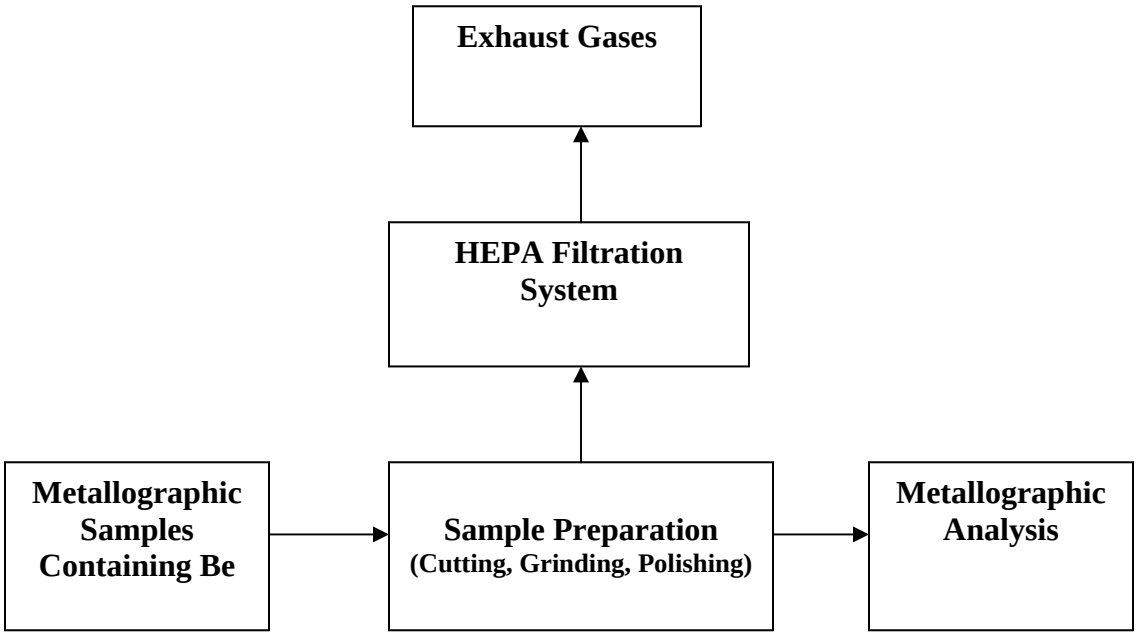
Attachment A

Process Flow Diagram

Process Flow Diagram for Utility Building Boilers



Process Flow Diagram for Metallographic Sample Preparation



Attachment B

Plot Plan

Chemistry and Metallurgy Research Replacement Facility Plot Plan

This page has been removed for operational security purposes. Please contact ENV-MAQ at (505) 665-8855 for a hard copy of the CMRR Facility Plot Plan.

Attachment C

Emission Calculations

Discussion of Emission Calculations

This attachment contains emissions calculations which support the information shown in the application forms for the air emission sources associated with the Chemistry and Metallurgy Research Replacement Project (CMRR). The discussion below provides additional explanation of the basis for the attached emission estimates.

Overview

The CMRR will consist of three primary components: a Utility Building (UB), a combined Radiological Laboratory/Office Building (RLOB), and the primary building designated a Security Category I nuclear facility (CAT I). The primary air emission source within the CMRR will be the dual fuel boilers located within the UB. The boilers will provide hot water to both the RLOB and the CAT I facility. The primary boiler fuel will be natural gas. The boilers will be capable of using distillate fuel oil as a standby fuel in case of disruption to the natural gas supply to the facility. Located within the CAT I facility will be a metallographic process in which samples containing beryllium are prepared for analysis and may be subject to cutting, grinding, and polishing. An additional source of air emissions will be laboratory scale usage of chemicals within the RLOB and CAT I facility. As shown in Table III-B of this application, there will be five standby diesel generators for emergency power which qualify as exempted equipment. Potential radionuclide emissions associated with the CMRR are regulated by the U.S. EPA and do not fall within the scope of this application.

Boiler Emission Estimates

This application is for installation of five (5) forced-draft dual fuel boilers with each boiler having a maximum heat input capacity of 11 MMBtu/hr. At this time, the specific boiler vendor has not been selected. However, the performance specification for the units includes a requirement for a low NO_x burner system with a maximum NO_x emission of 30 ppm.

Without specific vendor supplied emission estimates, AP-42 emission factors have been used to estimate boiler emissions. Several conservative assumptions have been utilized to ensure estimated emissions are maximum potential values. First, the maximum heat input capacity of each boiler has not been derated for the high altitude present at site conditions. In addition, for the primary pollutants of concern, NO_x and CO, the AP-42 factors have been increased by 20%. An exception is the NO_x emission factor for distillate fuel oil, in which case no control is assumed from the low NO_x burner system. It has also been assumed the distillate fuel oil will have a maximum sulfur content of 0.5%, when existing LANL sources such as the TA-3 Power Plant utilize fuel oil with a maximum sulfur content of 0.05%.

Annual ton per year (tpy) emission estimates assume all five boilers will operate at maximum capacity for 8,760 hours per year when burning natural gas. It is also assumed 289,100 gallons per year of fuel oil would be consumed (equivalent to a one month supply at maximum capacity) in addition to operation with natural gas.

The annual potential to emit emission rates for the UB boilers are estimated to be: 17.2 tpy NO_x, 24.9 tpy CO, 11.8 tpy SO_x, 2.3 tpy PM, 2.1 tpy PM_{10}, and 1.3 tpy VOC.

Hazardous air pollutant (HAP) emission estimates are also based on AP-42 emission factors and assumed full operation of all five boilers with natural gas and the fuel oil restriction noted above. The annual potential to emit emission rate for the boilers is 0.5 tpy HAP.

Note that as shown in this attachment, the short-term emission rates in grams/second which are used within the dispersion modeling analysis in Attachment K are based on the higher value when comparing the natural gas verses fuel oil short-term emission rates.

Chemical Usage Emission Estimates

Small quantities of chemicals will be used within the CMRR laboratory operations. It is anticipated chemical usage within the CMRR will be similar to past usage within the existing Chemistry and Metallurgy Research (CMR) facility at Technical Area (TA)-3-29. For air quality purposes, chemicals are categorized as VOC and/or HAP (some compounds are both VOC and HAP).

LANL currently has in place a system to estimate and report VOC and HAP emissions from chemical usage on a facility-wide basis. These estimates are conservative in that it is typically assumed 100% of a chemical purchased is emitted to the air. A review of the last five years (1999 to 2003) was done of VOC and HAP emissions from the existing CMR facility. As shown in this attachment, the maximum VOC emission rate for the five year period was 348.1 lb/yr. The maximum HAP emission rate for the same five year period was 235.7 lb/yr. VOC and HAP emission estimates for the CMRR are significantly higher than these past values in order to ensure a conservative estimate is provided.

The potential to emit annual VOC emissions from the CMRR are estimated to be 7.5 tpy. Annual HAP emissions are estimated to be 0.35 tpy.

Metallographic Sample Preparation

Within the CAT I facility, samples which contain beryllium will be prepared for metallographic analysis. Sample preparation will include cutting, grinding, and polishing operations which could emit beryllium particles. Records for similar operations at the existing CMR facility and the TA-55 Plutonium Facility were reviewed to estimate both the number of samples prepared and the amount of beryllium lost per sample processed. A conservative estimate for samples prepared is 5 samples per 24 hours and 300 samples per year. The maximum quantity of beryllium lost per sample is estimated to be 2 grams per sample.

The cutting, grinding, and polishing operations are conducted wet under a lubricant bath that traps displaced beryllium. These operations are also conducted under negative pressure within a glove box. All machined beryllium which may become airborne passes through the glove box ventilation system which is controlled by a HEPA filter.

Exhaust is further controlled by a HEPA filter bank with three filters. Each HEPA filter has a minimum removal efficiency of 99.95%. Maximum controlled or potential beryllium emissions have been conservatively estimated assuming only one HEPA filter is present and no removal from the wet process.

The maximum potential to emit beryllium emission rates are estimated to be 0.5 grams Be/24 hours and 3.0 grams Be/year. These requested emission limits are higher than calculated controlled emission rates in order to provide a safety factor for compliance, as well as establish an emission limit which is above the minimum detectable limit provided by the test method. A review of past beryllium emission tests at LANL on machining operations indicates there has only been one test in which potentially any amount of beryllium was measured. All other emissions tests have reported results below the minimum detectable limit of the test method.

Beryllium emissions are reported in terms of grams Be/24 hours because these are the units of the applicable standard at 40 CFR Part 61, Subpart C – National Emission Standard for Beryllium. Recent NMED NSR permits for LANL beryllium operations have established emission limits in terms of grams/24 hours and grams/yr, rather than lb/hr or tpy.

CRITERIA POLLUTANT EMISSION ESTIMATES
CMR REPLACEMENT PROJECT
UTILITY BUILDING BOILERS

Operational Data

Fuel				
Natural gas				
Heat Content	1012.9	Btu/scf		
Sulfur Content	2	grains/100 scf		
Distillate Fuel Oil				
Heat Content	137,000	Btu/gallon		
Sulfur Content	0.5	%		
Boilers (each)				
Maximum Heat Input (nameplate)	11	MMBtu/hr		
Maximum Fuel Consumption - gas	0.0109	MM scf/hr		
Maximum Fuel Consumption - oil	0.0803	M gal/hr	Annual Limit (all)	289.1 M gal/yr

Notes

1 Sulfur content of natural gas is 2 gr/100 scf as specified by PNM in correspondence with LANL.
2 Sulfur content of distillate fuel oil assumes maximum concentration for 40 CFR Part 60, Subpart Dc compliance.
3 Annual fuel limit for standby fuel (distillate fuel oil) is based on 1 month per year or 720 hours (30 x 24).
4 Boiler maximum heat input is nameplate rated capacity and is not derated for altitude. Actual capacity at site elevation will be less than this value.

CRITERIA POLLUTANT EMISSION ESTIMATES
CMR REPLACEMENT PROJECT
UTILITY BUILDING BOILERS

Emission Factors

	NOx	CO	SOx	PM	PM_{10}	VOC
Boiler - natural gas (lb/MM scf)	60	101	5.7	7.6	7.6	5.5
Boiler - fuel oil (lb/M gal)	20	6	72	3.3	2.3	0.2

Notes

Emission Factors - Boilers - natural gas

1 All factors are from AP-42, 7/98, Section 1.4 - Natural Gas Combustion.
2 NOx - The AP-42 factor for Low NOx burners has been increased by 20% [(50 x 0.2) + 50 = 60]
3 CO - The AP-42 factor has been increased by 20% [(84 x 0.2) + 84 = 101]
4 SOx - 2 gr S/100 scf, or 20,000 gr S/MM scf x lb/7000 gr x 2 lbs SO2/1 lb S.

Emission Factors - Boilers - fuel oil

1 All factors are from AP-42, 9/98, Section 1.3 Fuel Oil Combustion.
2 NOx - AP-42 does not provide a controlled emission factor for Low NOx burners, but states controlled emissions should be 35 to 55 percent lower than this factor.
3 SOx - Using S value of 0.5%, the AP-42 emission factor is (142 x 0.5) + (2 x 0.5) = 72
4 PM - From AP-42, factor is sum of condensable and filterable (1.3 + 2 = 3.3)
5 PM_{10} - From AP-42, factor is sum of condensable and filterable (1.3 + 1 = 2.3)
6 CO - The AP-42 factor has been increased by 20% [(5 x .2) + 5 = 6]

CRITERIA POLLUTANT EMISSION ESTIMATES
CMR REPLACEMENT PROJECT
UTILITY BUILDING BOILERS

Emission Estimates - lb/hr

	NOx	CO	SOx	PM	PM_{10}	VOC
Boiler (each) - natural gas	0.7	1.1	0.1	0.1	0.1	0.1
Boiler (each) - fuel oil	1.6	0.5	5.8	0.3	0.2	0.02

Emission Estimates - ton/year (Potential Emission Rate without fuel restrictions)

	NOx	CO	SOx	PM	PM_{10}	VOC
Boilers (all) - natural gas	14.3	24.0	1.4	1.8	1.8	1.3
Boilers (all) - fuel oil	35.2	10.6	126.6	5.8	4.0	0.4
Total	35.2	24.0	126.6	5.8	4.0	1.3

Note

Totals reflect highest value from boilers using either gas or oil at 8,760 hours per year.

Emission Estimates - ton/year (Potential to Emit with fuel oil restriction)

	NOx	CO	SOx	PM	PM_{10}	VOC
Boilers (all) - natural gas	14.3	24.0	1.4	1.8	1.8	1.3
Boilers (all) - fuel oil	2.9	0.9	10.4	0.5	0.3	0.03
Total	17.2	24.9	11.8	2.3	2.1	1.3

Note

Totals assume 8,760 hours per year operation with natural gas plus fuel oil use of 289,100 gallons.

CRITERIA POLLUTANT EMISSION ESTIMATES
CMR REPLACEMENT PROJECT
CHEMICAL USAGE

Past Actual VOC Emission Estimates - Existing CMR Operations- lb/year

Year		VOC (lb/yr)
1999		204.8
2000		145.5
2001		79.3
2002		348.1
2003		16
	Average	158.7

Note

Source of data is LANL chemical inventory system Chem-Log.

Potential VOC Emission Estimates - CMR Replacement Project - ton/yr

	VOC (ton/yr)
RLUOB	2.5
CAT I Facility	5
Total	7.5

HAP EMISSION ESTIMATES
CMR REPLACEMENT PROJECT

HAP Emission Estimates - Boilers - natural gas

HAP		Emission Factor	Emission Estimates	
			lb/hr	tpy
Organics		lb/ MM scf	(each boiler)	(all boilers)
	POM	8.82E-05	9.58E-07	2.10E-05
	Benzene	2.10E-03	2.28E-05	4.99E-04
	Dichlorobenzene	1.20E-03	1.30E-05	2.85E-04
	Formaldehyde	7.50E-02	8.14E-04	1.78E-02
	Hexane	1.80E+00	1.95E-02	4.28E-01
	Naphthalene	6.10E-04	6.62E-06	1.45E-04
	Toluene	3.40E-03	3.69E-05	8.09E-04
Metals				
	Arsenic	2.00E-04	2.17E-06	4.76E-05
	Beryllium	1.20E-05	1.30E-07	2.85E-06
	Cadmium	1.10E-03	1.19E-05	2.62E-04
	Chromium	1.40E-03	1.52E-05	3.33E-04
	Cobalt	8.40E-05	9.12E-07	2.00E-05
	Lead	5.00E-04	5.43E-06	1.19E-04
	Manganese	3.80E-04	4.13E-06	9.04E-05
	Mercury	2.60E-04	2.82E-06	6.18E-05
	Nickel	2.10E-03	2.28E-05	4.99E-04
	Selenium	2.40E-05	2.61E-07	5.71E-06
			total	4.49E-01
POM				
	2-Methylnaphthalene	2.40E-05		
	3-Methylchloranthrene	1.80E-06	POM estimates above	
	7,12-Dimethylbenz(a)anthracene	1.60E-05	under Organics.	
	Acenaphthene	1.80E-06		
	Acenaphthylene	1.80E-06		
	Anthracene	2.40E-06		
	Benz(a)anthracene	1.80E-06		
	Benzo(a)pyrene	1.20E-06		
	Benzo(b)fluoranthene	1.80E-06		
	Benzo(g,h,i)perylene	1.20E-06		
	Benzo(k)fluoranthene	1.80E-06		
	Chrysene	1.80E-06		
	Dibenzo(a,h)anthracene	1.20E-06		
	Fluoranthene	3.00E-06		
	Fluorene	2.80E-06		
	Indeno(1,2,3-cd)pyrene	1.80E-06		
	Phenanathrene	1.70E-05		
	Pyrene	5.00E-06		
	total	8.82E-05		

Note

All emission factors from AP-42, 7/98, Section 1.4 - Natural Gas Combustion,Tables 1.4-2, 1.4-3, and 1.4-4.

HAP EMISSION ESTIMATES
CMR REPLACEMENT PROJECT

HAP Emission Estimates - Boilers - distillate fuel oil

HAP		Emission Factor	Emission Estimates lb/hr	tpy
Organics		lb/1000 gal	(each boiler)	(all boilers)
	Benzene	2.75E-03	2.21E-04	3.97E-04
	Formaldehyde	4.80E-02	3.85E-03	6.94E-03
	Naphthalene	3.30E-04	2.65E-05	4.77E-05
	POM	3.30E-03	2.65E-04	4.77E-04
Metals				
	Arsenic	5.48E-04	4.40E-05	7.92E-05
	Beryllium	4.11E-04	3.30E-05	5.94E-05
	Cadmium	4.11E-04	3.30E-05	5.94E-05
	Chromium	4.11E-04	3.30E-05	5.94E-05
	Lead	1.23E-03	9.88E-05	1.78E-04
	Manganese	8.22E-04	6.60E-05	1.19E-04
	Mercury	4.11E-04	3.30E-05	5.94E-05
	Nickel	4.11E-04	3.30E-05	5.94E-05
	Selenium	2.06E-03	1.65E-04	2.98E-04
			total	8.83E-03

Notes

1 All emission factors from AP-42, 9/98, Section 1.3, Fuel Oil Combustion, Tables 1.3-8 and 1.3-10, for distillate oil, except benzene and naphthalene, from EPA FIRE database.

2 Emission factors for metals converted from lb/10^{12} Btu to lb/1000 gal using fuel oil heat rate of 137,000 Btu/gal.

HAP Emission Estimates - Chemical Usage

Year	Past Actual Emission Estimate	lb/yr	tpy
1999	**Maximum**	**235.7**	**0.12**
2000		54.9	
2001		133.8	
2002		175.9	
2003		103	

Note

Source of data is LANL chemical inventory system Chem-Log.

HAP Emission Estimates - Annual Total

Source	HAP Estimate tpy
Boilers - gas	4.49E-01
Boilers - oil	8.83E-03
Chemical Usage	3.54E-01
total	8.12E-01

Note

Annual estimate for chemical usage is 3 times past actual maximum (3 x 0.12 tpy).

EMISSION ESTIMATES
DISPERSION MODELING
CMR REPLACEMENT PROJECT

Emission Estimates - lb/hr

	NOx	CO	SOx	PM	PM_{10}
Boiler (each) - natural gas	0.7	1.1	0.1	0.1	0.1
Boiler (each) - fuel oil	1.6	0.5	5.8	0.3	0.2

Emission Estimates - g/s

	NOx	CO	SOx	PM	PM_{10}
Boiler (each)	0.20	0.14	0.73	0.03	0.02
Boiler (total)	1.01	0.69	3.64	0.17	0.12

Notes

1 For model input, selected higher value from natural gas verses oil (shaded value).
2 To convert lb/hr to g/s, multiply by 0.126.
3 The total boiler value was modeled to reflect five boilers exhaust to a one common stack.

Metallography Emission Estimates

Metallography Operational Data

Samples processed[1]	5	24 hours
	300	year
Maximum loss per sample[2]	2	grams Be
Control efficiency[3]	99.95	%

Notes

[1]Sample numbers are proposed permit conditions.

[2]Conservative estimate based on historical information at CMR and TA-55 metallography operations.

[3]Conservative value. Operations are conducted wet, within a glovebox controlled by a HEPA filter, and followed by a HEPA filter bank with (3) filters. Each HEPA filter rated at 99.95% removal efficiency.

Emission Estimates - Beryllium

	gm /24 hr	gm /yr
Uncontrolled[1]	10	600
Controlled[2]	0.005	0.3
Emission limit[3]	0.5	3.0

Notes

[1]Assumes no controls but maximum number of samples per 24-hours and annually.

[2]Based on conservative value of 99.95% removal efficiency.

[3]The proposed 24-hour emission limit includes a safety factor and is intended to be high enough to allow a clear compliance determination during startup emission testing.

Attachment D

Emissions Information

AP-42 Emission Factors

1.4 Natural Gas Combustion

1.4.1 General[1-2]

Natural gas is one of the major combustion fuels used throughout the country. It is mainly used to generate industrial and utility electric power, produce industrial process steam and heat, and heat residential and commercial space. Natural gas consists of a high percentage of methane (generally above 85 percent) and varying amounts of ethane, propane, butane, and inerts (typically nitrogen, carbon dioxide, and helium). The average gross heating value of natural gas is approximately 1,020 British thermal units per standard cubic foot (Btu/scf), usually varying from 950 to 1,050 Btu/scf.

1.4.2 Firing Practices[3-5]

There are three major types of boilers used for natural gas combustion in commercial, industrial, and utility applications: watertube, firetube, and cast iron. Watertube boilers are designed to pass water through the inside of heat transfer tubes while the outside of the tubes is heated by direct contact with the hot combustion gases and through radiant heat transfer. The watertube design is the most common in utility and large industrial boilers. Watertube boilers are used for a variety of applications, ranging from providing large amounts of process steam, to providing hot water or steam for space heating, to generating high-temperature, high-pressure steam for producing electricity. Furthermore, watertube boilers can be distinguished either as field erected units or packaged units.

Field erected boilers are boilers that are constructed on site and comprise the larger sized watertube boilers. Generally, boilers with heat input levels greater than 100 MMBtu/hr, are field erected. Field erected units usually have multiple burners and, given the customized nature of their construction, also have greater operational flexibility and NO_x control options. Field erected units can also be further categorized as wall-fired or tangential-fired. Wall-fired units are characterized by multiple individual burners located on a single wall or on opposing walls of the furnace while tangential units have several rows of air and fuel nozzles located in each of the four corners of the boiler.

Package units are constructed off-site and shipped to the location where they are needed. While the heat input levels of packaged units may range up to 250 MMBtu/hr, the physical size of these units are constrained by shipping considerations and generally have heat input levels less than 100 MMBtu/hr. Packaged units are always wall-fired units with one or more individual burners. Given the size limitations imposed on packaged boilers, they have limited operational flexibility and cannot feasibly incorporate some NO_x control options.

Firetube boilers are designed such that the hot combustion gases flow through tubes, which heat the water circulating outside of the tubes. These boilers are used primarily for space heating systems, industrial process steam, and portable power boilers. Firetube boilers are almost exclusively packaged units. The two major types of firetube units are Scotch Marine boilers and the older firebox boilers. In cast iron boilers, as in firetube boilers, the hot gases are contained inside the tubes and the water being heated circulates outside the tubes. However, the units are constructed of cast iron rather than steel. Virtually all cast iron boilers are constructed as package boilers. These boilers are used to produce either low-pressure steam or hot water, and are most commonly used in small commercial applications.

Natural gas is also combusted in residential boilers and furnaces. Residential boilers and furnaces generally resemble firetube boilers with flue gas traveling through several channels or tubes with water or air circulated outside the channels or tubes.

Table 1.4-1. EMISSION FACTORS FOR NITROGEN OXIDES (NO_x) AND CARBON MONOXIDE (CO) FROM NATURAL GAS COMBUSTION[a]

Combustor Type (MMBtu/hr Heat Input) [SCC]	NO_x[b]		CO	
	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating
Large Wall-Fired Boilers (>100) [1-01-006-01, 1-02-006-01, 1-03-006-01]				
Uncontrolled (Pre-NSPS)[c]	280	A	84	B
Uncontrolled (Post-NSPS)[c]	190	A	84	B
Controlled - Low NO_x burners	140	A	84	B
Controlled - Flue gas recirculation	100	D	84	B
Small Boilers (<100) [1-01-006-02, 1-02-006-02, 1-03-006-02, 1-03-006-03]				
Uncontrolled	100	B	84	B
Controlled - Low NO_x burners	50	D	84	B
Controlled - Low NO_x burners/Flue gas recirculation	32	C	84	B
Tangential-Fired Boilers (All Sizes) [1-01-006-04]				
Uncontrolled	170	A	24	C
Controlled - Flue gas recirculation	76	D	98	D
Residential Furnaces (<0.3) [No SCC]				
Uncontrolled	94	B	40	B

[a] Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. To convert from $lb/10^6$ scf to $kg/10^6$ m^3, multiply by 16. Emission factors are based on an average natural gas higher heating value of 1,020 Btu/scf. To convert from $1b/10^6$ scf to lb/MMBtu, divide by 1,020. The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value. SCC = Source Classification Code. ND = no data. NA = not applicable.

[b] Expressed as NO_2. For large and small wall fired boilers with SNCR control, apply a 24 percent reduction to the appropriate NO_X emission factor. For tangential-fired boilers with SNCR control, apply a 13 percent reduction to the appropriate NO_X emission factor.

[c] NSPS=New Source Performance Standard as defined in 40 CFR 60 Subparts D and Db. Post-NSPS units are boilers with greater than 250 MMBtu/hr of heat input that commenced construction modification, or reconstruction after August 17, 1971, and units with heat input capacities between 100 and 250 MMBtu/hr that commenced construction modification, or reconstruction after June 19, 1984.

TABLE 1.4-2. EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSE GASES FROM NATURAL GAS COMBUSTION[a]

Pollutant	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating
CO_2[b]	120,000	A
Lead	0.0005	D
N_2O (Uncontrolled)	2.2	E
N_2O (Controlled-low-NO_X burner)	0.64	E
PM (Total)[c]	7.6	D
PM (Condensable)[c]	5.7	D
PM (Filterable)[c]	1.9	B
SO_2[d]	0.6	A
TOC	11	B
Methane	2.3	B
VOC	5.5	C

[a] Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. Data are for all natural gas combustion sources. To convert from $lb/10^6$ scf to $kg/10^6$ m^3, multiply by 16. To convert from $lb/10^6$ scf to 1b/MMBtu, divide by 1,020. The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value. TOC = Total Organic Compounds. VOC = Volatile Organic Compounds.

[b] Based on approximately 100% conversion of fuel carbon to CO_2. $CO_2[lb/10^6 \text{ scf}] = (3.67)(CON)(C)(D)$, where CON = fractional conversion of fuel carbon to CO_2, C = carbon content of fuel by weight (0.76), and D = density of fuel, 4.2×10^4 $lb/10^6$ scf.

[c] All PM (total, condensible, and filterable) is assumed to be less than 1.0 micrometer in diameter. Therefore, the PM emission factors presented here may be used to estimate PM_{10}, $PM_{2.5}$ or PM_1 emissions. Total PM is the sum of the filterable PM and condensible PM. Condensible PM is the particulate matter collected using EPA Method 202 (or equivalent). Filterable PM is the particulate matter collected on, or prior to, the filter of an EPA Method 5 (or equivalent) sampling train.

[d] Based on 100% conversion of fuel sulfur to SO_2. Assumes sulfur content is natural gas of 2,000 grains/10^6 scf. The SO_2 emission factor in this table can be converted to other natural gas sulfur contents by multiplying the SO_2 emission factor by the ratio of the site-specific sulfur content (grains/10^6 scf) to 2,000 grains/10^6 scf.

TABLE 1.4-3. EMISSION FACTORS FOR SPECIATED ORGANIC COMPOUNDS FROM NATURAL GAS COMBUSTION[a]

CAS No.	Pollutant	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating
91-57-6	2-Methylnaphthalene[b, c]	2.4E-05	D
56-49-5	3-Methylchloranthrene[b, c]	<1.8E-06	E
	7,12-Dimethylbenz(a)anthracene[b,c]	<1.6E-05	E
83-32-9	Acenaphthene[b,c]	<1.8E-06	E
203-96-8	Acenaphthylene[b,c]	<1.8E-06	E
120-12-7	Anthracene[b,c]	<2.4E-06	E
56-55-3	Benz(a)anthracene[b,c]	<1.8E-06	E
71-43-2	Benzene[b]	2.1E-03	B
50-32-8	Benzo(a)pyrene[b,c]	<1.2E-06	E
205-99-2	Benzo(b)fluoranthene[b,c]	<1.8E-06	E
191-24-2	Benzo(g,h,i)perylene[b,c]	<1.2E-06	E
205-82-3	Benzo(k)fluoranthene[b,c]	<1.8E-06	E
106-97-8	Butane	2.1E+00	E
218-01-9	Chrysene[b,c]	<1.8E-06	E
53-70-3	Dibenzo(a,h)anthracene[b,c]	<1.2E-06	E
25321-22-6	Dichlorobenzene[b]	1.2E-03	E
74-84-0	Ethane	3.1E+00	E
206-44-0	Fluoranthene[b,c]	3.0E-06	E
86-73-7	Fluorene[b,c]	2.8E-06	E
50-00-0	Formaldehyde[b]	7.5E-02	B
110-54-3	Hexane[b]	1.8E+00	E
193-39-5	Indeno(1,2,3-cd)pyrene[b,c]	<1.8E-06	E
91-20-3	Naphthalene[b]	6.1E-04	E
109-66-0	Pentane	2.6E+00	E
85-01-8	Phenanathrene[b,c]	1.7E-05	D

TABLE 1.4-3. EMISSION FACTORS FOR SPECIATED ORGANIC COMPOUNDS FROM NATURAL GAS COMBUSTION (Continued)

CAS No.	Pollutant	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating
74-98-6	Propane	1.6E+00	E
129-00-0	Pyrene[b, c]	5.0E-06	E
108-88-3	Toluene[b]	3.4E-03	C

[a] Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. Data are for all natural gas combustion sources. To convert from $lb/10^6$ scf to $kg/10^6$ m^3, multiply by 16. To convert from $1b/10^6$ scf to lb/MMBtu, divide by 1,020. Emission Factors preceeded with a less-than symbol are based on method detection limits.

[b] Hazardous Air Pollutant (HAP) as defined by Section 112(b) of the Clean Air Act.

[c] HAP because it is Polycyclic Organic Matter (POM). POM is a HAP as defined by Section 112(b) of the Clean Air Act.

[d] The sum of individual organic compounds may exceed the VOC and TOC emission factors due to differences in test methods and the availability of test data for each pollutant.

TABLE 1.4-4. EMISSION FACTORS FOR METALS FROM NATURAL GAS COMBUSTION[a]

CAS No.	Pollutant	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating
7440-38-2	Arsenic[b]	2.0E-04	E
7440-39-3	Barium	4.4E-03	D
7440-41-7	Beryllium[b]	<1.2E-05	E
7440-43-9	Cadmium[b]	1.1E-03	D
7440-47-3	Chromium[b]	1.4E-03	D
7440-48-4	Cobalt[b]	8.4E-05	D
7440-50-8	Copper	8.5E-04	C
7439-96-5	Manganese[b]	3.8E-04	D
7439-97-6	Mercury[b]	2.6E-04	D
7439-98-7	Molybdenum	1.1E-03	D
7440-02-0	Nickel[b]	2.1E-03	C
7782-49-2	Selenium[b]	<2.4E-05	E
7440-62-2	Vanadium	2.3E-03	D
7440-66-6	Zinc	2.9E-02	E

[a] Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. Data are for all natural gas combustion sources. Emission factors preceeded by a less-than symbol are based on method detection limits. To convert from $lb/10^6$ scf to $kg/10^6$ m^3, multiply by l6. To convert from $lb/10^6$ scf to 1b/MMBtu, divide by 1,020.

[b] Hazardous Air Pollutant as defined by Section 112(b) of the Clean Air Act.

1.3 Fuel Oil Combustion

1.3.1 General[1-3]

Two major categories of fuel oil are burned by combustion sources: distillate oils and residual oils. These oils are further distinguished by grade numbers, with Nos. 1 and 2 being distillate oils; Nos. 5 and 6 being residual oils; and No. 4 being either distillate oil or a mixture of distillate and residual oils. No. 6 fuel oil is sometimes referred to as Bunker C. Distillate oils are more volatile and less viscous than residual oils. They have negligible nitrogen and ash contents and usually contain less than 0.3 percent sulfur (by weight). Distillate oils are used mainly in domestic and small commercial applications, and include kerosene and diesel fuels. Being more viscous and less volatile than distillate oils, the heavier residual oils (Nos. 5 and 6) may need to be heated for ease of handling and to facilitate proper atomization. Because residual oils are produced from the residue remaining after the lighter fractions (gasoline, kerosene, and distillate oils) have been removed from the crude oil, they contain significant quantities of ash, nitrogen, and sulfur. Residual oils are used mainly in utility, industrial, and large commercial applications.

1.3.2 Firing Practices[4]

The major boiler configurations for fuel oil-fired combustors are watertube, firetube, cast iron, and tubeless design. Boilers are classified according to design and orientation of heat transfer surfaces, burner configuration, and size. These factors can all strongly influence emissions as well as the potential for controlling emissions.

Watertube boilers are used in a variety of applications ranging from supplying large amounts of process steam to providing space heat for industrial facilities. In a watertube boiler, combustion heat is transferred to water flowing through tubes which line the furnace walls and boiler passes. The tube surfaces in the furnace (which houses the burner flame) absorb heat primarily by radiation from the flames. The tube surfaces in the boiler passes (adjacent to the primary furnace) absorb heat primarily by convective heat transfer.

Firetube boilers are used primarily for heating systems, industrial process steam generators, and portable power boilers. In firetube boilers, the hot combustion gases flow through the tubes while the water being heated circulates outside of the tubes. At high pressures and when subjected to large variations in steam demand, firetube units are more susceptible to structural failure than watertube boilers. This is because the high-pressure steam in firetube units is contained by the boiler walls rather than by multiple small-diameter watertubes, which are inherently stronger. As a consequence, firetube boilers are typically small and are used primarily where boiler loads are relatively constant. Nearly all firetube boilers are sold as packaged units because of their relatively small size.

A cast iron boiler is one in which combustion gases rise through a vertical heat exchanger and out through an exhaust duct. Water in the heat exchanger tubes is heated as it moves upward through the tubes. Cast iron boilers produce low pressure steam or hot water, and generally burn oil or natural gas. They are used primarily in the residential and commercial sectors.

Another type of heat transfer configuration used on smaller boilers is the tubeless design. This design incorporates nested pressure vessels with water in between the shells. Combustion gases are fired into the inner pressure vessel and are then sometimes recirculated outside the second vessel.

Table 1.3-1. CRITERIA POLLUTANT EMISSION FACTORS FOR FUEL OIL COMBUSTION[a]

Firing Configuration (SCC)[a]	SO_2[b]		SO_3[c]		NO_x[d]		CO[e]		Filterable PM[f]	
	Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING	Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING	Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING	Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING	Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING
Boilers > 100 Million Btu/hr										
No. 6 oil fired, normal firing (1-01-004-01), (1-02-004-01), (1-03-004-01)	157S	A	5.7S	C	47	A	5	A	9.19(S)+3.22	A
No. 6 oil fired, normal firing, low NO_x burner (1-01-004-01), (1-02-004-01)	157S	A	5.7S	C	40	B	5	A	9.19(S)+3.22	A
No. 6 oil fired, tangential firing, (1-01-004-04)	157S	A	5.7S	C	32	A	5	A	9.19(S)+3.22	A
No. 6 oil fired, tangential firing, low NO_x burner (1-01-004-04)	157S	A	5.7S	C	26	E	5	A	9.19(S)+3.22	A
No. 5 oil fired, normal firing (1-01-004-05), (1-02-004-04)	157S	A	5.7S	C	47	B	5	A	10	B
No. 5 oil fired, tangential firing (1-01-004-06)	157S	A	5.7S	C	32	B	5	A	10	B
No. 4 oil fired, normal firing (1-01-005-04), (1-02-005-04)	150S	A	5.7S	C	47	B	5	A	7	B
No. 4 oil fired, tangential firing (1-01-005-05)	150S	A	5.7S	C	32	B	5	A	7	B
No. 2 oil fired (1-01-005-01), (1-02-005-01), (1-03-005-01)	157S	A	5.7S	C	24	D	5	A	2	A
No.2 oil fired, LNB/FGR, (1-01-005-01), (1-02-005-01), (1-03-005-01)	157S	A	5.7S	A	10	D	5	A	2	A

Table 1.3-1. (cont.)

Firing Configuration (SCC)[a]	SO_2[b]		SO_3[c]		NO_x[d]		CO[e]		Filterable PM[f]	
	Emission Factor ($lb/10^3$ gal)	EMISSION FACTOR RATING	Emission Factor ($lb/10^3$ gal)	EMISSION FACTOR RATING	Emission Factor ($lb/10^3$ gal)	EMISSION FACTOR RATING	Emission Factor ($lb/10^3$ gal)	EMISSION FACTOR RATING	Emission Factor ($lb/10^3$ gal)	EMISSION FACTOR RATING
Boilers < 100 Million Btu/hr										
No. 6 oil fired (1-02-004-02/03) (1-03-004-02/03)	157S	A	2S	A	55	A	5	A	10	B
No. 5 oil fired (1-03-004-04)	157S	A	2S	A	55	A	5	A	9.19(S)+3.22	A
No. 4 oil fired (1-03-005-04)	150S	A	2S	A	20	A	5	A	7	B
Distillate oil fired (1-02-005-02/03) (1-03-005-02/03)	142S	A	2S	A	20	A	5	A	2	A
Residential furnace (A2104004/A2104011)	142S	A	2S	A	18	A	5	A	0.4[g]	B

[a] To convert from $lb/10^3$ gal to $kg/10^3$ L, multiply by 0.120. SCC = Source Classification Code.

[b] References 1-2,6-9,14,56-60. S indicates that the weight % of sulfur in the oil should be multiplied by the value given. For example, if the fuel is 1% sulfur, then S = 1.

[c] References 1-2,6-8,16,57-60. S indicates that the weight % of sulfur in the oil should be multiplied by the value given. For example, if the fuel is 1% sulfur, then S = 1.

[d] References 6-7,15,19,22,56-62. Expressed as NO_2. Test results indicate that at least 95% by weight of NO_x is NO for all boiler types except residential furnaces, where about 75% is NO. For utility vertical fired boilers use 105 $lb/10^3$ gal at full load and normal (>15%) excess air. Nitrogen oxides emissions from residual oil combustion in industrial and commercial boilers are related to fuel nitrogen content, estimated by the following empirical relationship: lb $NO_2/10^3$ gal = 20.54 + 104.39(N), where N is the weight % of nitrogen in the oil. For example, if the fuel is 1% nitrogen, then N = 1.

[e] References 6-8,14,17-19,56-61. CO emissions may increase by factors of 10 to 100 if the unit is improperly operated or not well maintained.

[f] References 6-8,10,13-15,56-60,62-63. Filterable PM is that particulate collected on or prior to the filter of an EPA Method 5 (or equivalent) sampling train. Particulate emission factors for residual oil combustion are, on average, a function of fuel oil sulfur content where S is the weight % of sulfur in oil. For example, if fuel oil is 1% sulfur, then S = 1.

[g] Based on data from new burner designs. Pre-1970's burner designs may emit filterable PM as high as 3.0 $1b/10^3$ gal.

Table 1.3-2. CONDENSABLE PARTICULATE MATTER EMISSION FACTORS FOR OIL COMBUSTION[a]

Firing Configuration[b] (SCC)	Controls	CPM - TOT[c, d]		CPM - IOR[c, d]		CPM - ORG[c, d]	
		Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING	Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING	Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING
No. 2 oil fired (1-01-005-01, 1-02-005-01, 1-03-005-01)	All controls, or uncontrolled	1.3[d, e]	D	65% of CPM-TOT emission factor[c]	D	35% of CPM-TOT emission factor[c]	D
No. 6 oil fired (1-01-004-01/04, 1-02-004-01, 1-03-004-01)	All controls, or uncontrolled	1.5[f]	D	85% of CPM-TOT emission factor[d]	E	15% of CPM-TOT emission factor[d]	E

[a] All condensable PM is assumed to be less than 1.0 micron in diameter.

[b] No data are available for numbers 3, 4, and 5 oil. For number 3 oil, use the factors provided for number 2 oil. For numbers 4 and 5 oil, use the factors provided for number 6 oil.

[c] CPM-TOT = total condensable particulate matter.
CPM-IOR = inorganic condensable particulate matter.
CPM-ORG = organic condensable particulate matter.

[d] To convert to lb/MMBtu of No. 2 oil, divide by 140 MMBtu/10^3 gal. To convert to lb/MMBtu of No. 6 oil, divide by 150 MMBtu/10^3 gal.

[e] References: 76-78.

[f] References: 79-82.

Table 1.3-3. EMISSION FACTORS FOR TOTAL ORGANIC COMPOUNDS (TOC), METHANE, AND NONMETHANE TOC (NMTOC) FROM UNCONTROLLED FUEL OIL COMBUSTION[a]

EMISSION FACTOR RATING: A

Firing Configuration (SCC)	TOC[b] Emission Factor ($lb/10^3$ gal)	Methane[b] Emission Factor ($lb/10^3$ gal)	NMTOC[b] Emission Factor ($lb/10^3$ gal)
Utility boilers			
No. 6 oil fired, normal firing (1-01-004-01)	1.04	0.28	0.76
No. 6 oil fired, tangential firing (1-01-004-04)	1.04	0.28	0.76
No. 5 oil fired, normal firing (1-01-004-05)	1.04	0.28	0.76
No. 5 oil fired, tangential firing (1-01-004-06)	1.04	0.28	0.76
No. 4 oil fired, normal firing (1-01-005-04)	1.04	0.28	0.76
No. 4 oil fired, tangential firing (1-01-005-05)	1.04	0.28	0.76
Industrial boilers			
No. 6 oil fired (1-02-004-01/02/03)	1.28	1.00	0.28
No. 5 oil fired (1-02-004-04)	1.28	1.00	0.28
Distillate oil fired (1-02-005-01/02/03)	0.252	0.052	0.2
No. 4 oil fired (1-02-005-04)	0.252	0.052	0.2
Commercial/institutional/residential combustors			
No. 6 oil fired (1-03-004-01/02/03)	1.605	0.475	1.13
No. 5 oil fired (1-03-004-04)	1.605	0.475	1.13
Distillate oil fired (1-03-005-01/02/03)	0.556	0.216	0.34
No. 4 oil fired (1-03-005-04)	0.556	0.216	0.34
Residential furnace (A2104004/A2104011)	2.493	1.78	0.713

[a] To convert from $lb/10^3$ gal to $kg/10^3$ L, multiply by 0.12. SCC = Source Classification Code.

[b] References 29-32. Volatile organic compound emissions can increase by several orders of magnitude if the boiler is improperly operated or is not well maintained.

Table 1.3-8. EMISSION FACTORS FOR NITROUS OXIDE (N_2O), POLYCYCLIC ORGANIC MATTER (POM), AND FORMALDEHYDE (HCOH) FROM FUEL OIL COMBUSTION[a]

EMISSION FACTOR RATING: E

Firing Configuration (SCC)	Emission Factor (lb/10^3 gal)		
	N_2O[b]	POM[c]	HCOH[c]
Utility/industrial/commercial boilers			
No. 6 oil fired (1-01-004-01, 1-02-004-01, 1-03-004-01)	0.11	0.0011 - 0.0013[d]	0.024 - 0.061
Distillate oil fired (1-01-005-01, 1-02-005-01, 1-03-005-01)	0.11	0.0033[e]	0.035 - 0.061
Residential furnaces (A2104004/A2104011)	0.05	ND	ND

[a] To convert from lb/10^3 gal to kg/10^3 L, multiply by 0.12. SCC = Source Classification Code. ND = no data.
[b] References 45-46. EMISSION FACTOR RATING = B.
[c] References 29-32.
[d] Particulate and gaseous POM.
[e] Particulate POM only.

Table 1.3-10. EMISSION FACTORS FOR TRACE ELEMENTS FROM DISTILLATE FUEL OIL COMBUSTION SOURCES[a]

EMISSION FACTOR RATING: E

Firing Configuration (SCC)	Emission Factor ($lb/10^{12}$ Btu)										
	As	Be	Cd	Cr	Cu	Pb	Hg	Mn	Ni	Se	Zn
Distillate oil fired (1-01-005-01, 1-02-005-01, 1-03-005-01)	4	3	3	3	6	9	3	6	3	15	4

[a] Data are for distillate oil fired boilers, SCC codes 1-01-005-01, 1-02-005-01, and 1-03-005-01. References 29-32, 40-44 and 83. To convert from $lb/10^{12}$ Btu to pg/J, multiply by 0.43.

Attachment E

Site Map

USGS Topographic Map showing the approximate location of the CMRR

This page has been removed for operational security purposes. Please contact ENV-MAQ at (505) 665-8855 for a hard copy of the USGS topographic map showing the approximate location of the CMRR.

Attachment F

Proof of Public Notice

Attachment F
Proof of Public Notice

This attachment contains copies of the public notice provided by Los Alamos National Laboratory for the Chemistry and Metallurgy Research Replacement (CMRR) facility. When all notice has been completed, documentation will be provided to NMED. Public notice includes:

- Certified letters to approximately 450 property owners near the LANL property boundary.
- Public notice in the local newspaper and on the radio.
- Posting of public notice in four (4) publicly accessible places.
- Certified letters to all cities, counties, and pueblos within a ten (10) mile radius.

Sample Letter to Nearby Property Owners

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Dear Madam or Sir:

This letter is to notify you the University of California, operator of Los Alamos National Laboratory for the U.S. Department of Energy, is preparing to apply to the New Mexico Environment Department's Air Quality Bureau for an air quality permit for the Chemistry and Metallurgy Research Replacement (CMRR) facility. This notice is a requirement of 20.2.72 NMAC – CONSTRUCTION PERMITS. We are providing this notice to you because you were identified as an owner of property which is located at or near the boundary of Los Alamos National Laboratory.

Los Alamos National Laboratory intends to submit the permit application to the New Mexico Environment Department's Air Quality Bureau in February 2005. Once submitted, the application will be available on line at http://www.airquality.lanl.gov/ConstrPermit.htm. The CMRR facility is located in Township 19 North, Range 6 East, Section 22, approximately 3 miles south of Los Alamos in Los Alamos County.

An air quality permit is sought for research and development activities involving analytical chemistry, materials characterization, and metallurgic studies on actinides and other metals. This facility will replace the existing Chemistry and Metallurgy Building, which has been in operation at Los Alamos National Laboratory since the 1950s. The estimated plant-wide, maximum air emissions and air pollutants from the CMRR are 0.3 pounds per hour and 2.3 tons per year of particulate matter, 1.1 pounds per hour and 24.9 tons per year of carbon monoxide, 5.8 pounds per hour and 11.8 tons per year of sulfur dioxide, 1.6 pounds per hour and 17.2 tons per year of nitrogen oxides, and 0.1 pounds per hour and 8.8 tons per year of volatile organic compounds. Maximum hazardous air pollutant emissions are 0.8 tons per year, including maximum estimated beryllium emissions of 0.5 grams per 24-hours and 3.0 grams per year. Potential emissions of radionuclides will be addressed in a preconstruction approval request to be filed with the U.S. EPA Region VI Office. The maximum and standard operating schedules of the facility will be 24 hours per day and 365 days per year.

The permit applicant and operator is the University of California at P.O. Box 1663, MS J978, Los Alamos, New Mexico 87545. The owner of the facility is the U.S. Department of Energy, Los Alamos Area Office, 528 35th Street, Los Alamos, NM 87544.

Inquiries about the permitting process or relevant comments or questions regarding this permit application may be directed to:

Program Manager, New Source Review
New Mexico Environment Department
Air Quality Bureau
2048 Galisteo
Santa Fe, New Mexico 87505
(505) 827-1494

If you send written comments to the Department, please be sure to note the name of the company and the name of the site, or a copy of this letter along with your comments so that the Department can determine the permit application to which your comments refer. Also include your mailing address in your response.

The Department will also publish a notice later in the permit process after it has had the opportunity to review the application and its air quality impacts.

Sincerely,

Jean Dewart
Group Leader
Environmental Stewardship Division
Meteorology and Air Quality Group
Los Alamos National Laboratory
P.O. Box 1663, MS J978
Los Alamos New Mexico, 87545

For Newspaper, Radio, and Posting

NOTICE OF AIR QUALITY PERMIT APPLICATION

Pursuant to the requirements of Title 20 of the New Mexico Administrative Code, Chapter 2, Part 72 (20.2.72 NMAC – CONSTRUCTION PERMITS, Section 203.B), the University of California, operator of Los Alamos National Laboratory at P.O. Box 1663, MS J978, Los Alamos, New Mexico 87545 for the U.S. Department of Energy, hereby announces the intent to apply to the New Mexico Environment Department's Air Quality Bureau for an air quality permit for the Chemistry and Metallurgy Research Replacement (CMRR) facility. An air quality permit is sought for research and development activities involving analytical chemistry, materials characterization, and metallurgic studies on actinides and other metals. This facility will replace the existing Chemistry and Metallurgy Building which has been in operation at Los Alamos National Laboratory since the 1950s. The expected date of application submittal to the NMED is February 2005.

The facility is located in Township 19 North, Range 6 East, Section 22, approximately 3 miles south of Los Alamos in Los Alamos County.

The estimated plant-wide, maximum air emissions and air pollutants from the CMRR are 0.3 pounds per hour and 2.3 tons per year of particulate matter, 1.1 pounds per hour and 24.9 tons per year of carbon monoxide, 5.8 pounds per hour and 11.8 tons per year of sulfur dioxide, 1.6 pounds per hour and 17.2 tons per year of nitrogen oxides, and 0.1 pounds per hour and 8.8 tons per year of volatile organic compounds. Maximum hazardous air pollutant emissions are 0.8 tons per year, including maximum estimated beryllium emissions of 0.5 grams per 24-hours and 3.0 grams per year. Potential emissions of radionuclides will be addressed in a preconstruction approval request to be filed with the U.S. EPA Region VI Office. The maximum and standard operating schedules of the facility will be 24 hours per day and 365 days per year. The permit applicant and operator is the University of California at P.O. Box 1663, MS J978, Los Alamos, New Mexico 87545. The owner of the facility is the U.S. Department of Energy, Los Alamos Area Office, 528 35th Street, Los Alamos, NM 87544. Inquiries about the permitting process or relevant comments or questions regarding this permit application may be directed to:

Program Manager, New Source Review
New Mexico Environment Department
Air Quality Bureau
2048 Galisteo Street
Santa Fe, New Mexico 87505
(505) 827-1494

Please refer to the company name and site name, as used in this notice or send a copy of this notice when making inquiries since the Department might not have received the permit application at the time of this notice. The Department will also publish a legal notice later during the application review process after it has had the opportunity to review the application and the air quality impacts.

Sample Letter to Municipality, County, and Tribal Governments

CERTIFIED MAIL **XXXX XXXX XXXX XXXX**
RETURN RECEIPT REQUESTED

Dear **[Municipal, County, or Tribal Official]**

This letter is to notify you that the University of California, operator of Los Alamos National Laboratory for the U.S. Department of Energy, is preparing to apply to the New Mexico Environment Department's Air Quality Bureau for an air quality permit for the Chemistry and Metallurgy Research Replacement (CMRR) facility. This notice is a requirement of 20.2.72 NMAC – CONSTRUCTION PERMITS.

Los Alamos National Laboratory expects to submit the permit application to the New Mexico Environment Department's Air Quality Bureau in February 2005. The location of the facility is Township 19 North, Range 6 East, Section 22 approximately 3 miles south from Los Alamos in Los Alamos County.

An air quality permit is sought for research and development activities involving analytical chemistry, materials characterization, and metallurgic studies on actinides and other metals. This facility will replace the existing Chemistry and Metallurgy Building which has been in operation at Los Alamos National Laboratory since the 1950s.

The estimated plant-wide, maximum air emissions and air pollutants from the CMRR are 0.3 pounds per hour and 2.3 tons per year of particulate matter, 1.1 pounds per hour and 24.9 tons per year of carbon monoxide, 5.8 pounds per hour and 11.8 tons per year of sulfur dioxide, 1.6 pounds per hour and 17.2 tons per year of nitrogen oxides, and 0.1 pounds per hour and 8.8 tons per year of volatile organic compounds. Maximum hazardous air pollutant emissions are 0.8 tons per year, including maximum estimated beryllium emissions of 0.5 grams per 24-hours and 3.0 grams per year. Potential emissions of radionuclides will be addressed in a preconstruction approval request to be filed with the U.S. EPA Region VI Office. The maximum and standard operating schedules of the facility will be 24 hours per day and 365 days per year. The permit applicant and operator is the University of California at P.O. Box 1663, MS J978, Los Alamos, New Mexico 87545. The owner of the facility is the U.S. Department of Energy, Los Alamos Area Office, 528 35th Street, Los Alamos, NM 87544.

Inquiries about the permitting process or relevant comments or questions regarding this permit application may be directed to:

Program Manager, New Source Review
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Santa Fe, New Mexico 87505
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If you send written comments to the Department, please be sure to note the name of the company and the name of the site, or a copy of this letter along with your comments so that the Department can determine the permit application to which your comments refer. Also include your mailing address in your response. The Department will also publish notice later in the permit process after it has had the opportunity to review the application and its air quality impacts.

Sincerely,

Jean Dewart
Group Leader
Environmental Stewardship Division
Meteorology and Air Quality Group
Los Alamos National Laboratory
P.O. Box 1663, MS J978
Los Alamos New Mexico, 87545

List of Municipalities and Counties Requiring Certified Notification

Los Alamos County Clerk
P.O. Box 30
Los Alamos, New Mexico 87544

Governor, Cochiti Pueblo
P.O. Box 70
Cochiti Pueblo, New Mexico 87072

Sandoval County Clerk
P.O. Box 40
Bernalillo, New Mexico 87004

Santa Fe County Clerk
P.O. Box 1985
Santa Fe, New Mexico 87501

Governor, San Ildefonso Pueblo
Route 5, Box 315A
Santa Fe, New Mexico 87501

Governor, Santa Clara Pueblo
P.O. Box 580
Espanola, New Mexico 87532

Espanola City Manager
P.O. Drawer 37
Espanola, New Mexico 87532

Governor, Jemez Pueblo
P.O. Box 100
Jemez Pueblo, New Mexico 87024

Governor, Pojoaque Pueblo
Route 11, Box 71
Santa Fe, New Mexico 87501

Rio Arriba County Clerk
P.O. Box 158
Tierra Amarilla, New Mexico 87575
Or
P.O. Box 1256
Espanola, New Mexico 87532

PROOF OF POSTING

This document is to verify that a "Notice of Air Permit Application" to the New Mexico Environment Department by the University of California, operator of Los Alamos National Laboratory (LANL) for the U.S. Department of Energy, for the **Chemistry and Metallurgy Research Replacement facility**, was posted at the following address:

Address where posted: *Los Alamos Public Library*
2400 Central Avenue
Los Alamos, New Mexico 87544

Name: _____ Signature: _____

Date: _____

PROOF OF POSTING

This document is to verify that a "Notice of Permit Application" to the New Mexico Environment Department by the University of California, operator of Los Alamos National Laboratory (LANL) for the U.S. Department of Energy, for the **Chemistry and Metallurgy Research Replacement facility**, was posted at the following address:

Address where posted: *Los Alamos National Laboratory*
Technical Area 55 Entrance
Los Alamos, New Mexico 87545

Name: _____ Signature: _____

Date: _____

PROOF OF POSTING

This document is to verify that a "Notice of Permit Application" to the New Mexico Environment Department by the University of California, operator of Los Alamos National Laboratory (LANL) for the U.S. Department of Energy, for the **Chemistry and Metallurgy Research Replacement facility**, was posted at the following address:

Address where posted: *Los Alamos County Building*
2300 Trinity Drive
Los Alamos, New Mexico 87544

Name: _____ Signature: _____

Date: _____

PROOF OF POSTING

This document is to verify that a "Notice of Permit Application" to the New Mexico Environment Department by the University of California, operator of Los Alamos National Laboratory (LANL) for the U.S. Department of Energy, for the **Chemistry and Metallurgy Research Replacement facility**, was posted at the following address:

Address where posted: *U.C. Northern New Mexico and LANL*
Outreach Center Community Reading Room
1619 Central Avenue
Los Alamos, New Mexico 87544

Name: _____ Signature: _____

Date: _____

Attachment G

Project Description

Attachment G
Project Description

Overview

The Chemistry and Metallurgy Research Replacement Facility (CMRR) will replace the existing Chemistry and Metallurgy Research Building (CMR) at Technical Area (TA)-3-29. The existing CMR Building is over 50 years old and many of its utilities and structural components are outdated and deteriorating. It has been determined that the current mission-critical CMR support capabilities should be continued within a new facility rather than attempt to repair and upgrade the current building.

The CMR Building's main function is to house research and development capabilities involving analytical chemistry, materials characterization, and metallurgic studies on actinides and other metals. These activities have been conducted almost continuously in the CMR Building since it became operational. Analytical chemistry and materials characterization services performed in the CMR Building support virtually every program at LANL. These functions will continue to be the primary purpose of the new CMRR.

The CMRR will be located adjacent to the TA-55 Plutonium Facility on Pajarito Road. There will be three primary buildings within the CMRR. One building will house laboratory and office space. The radiological laboratory will have approximately 20,000 square feet of space. Office space will be provided for 350 people as well as common, support, and storage areas. This building is referenced as the Radiological Laboratory/Office Building (RLOB). The Utility Building (UB) will provide utility infrastructure and support systems to all CMRR facilities. Together, these two buildings have been referenced as the RLUOB. The third building will be a Security Category I nuclear facility (CAT I) and will house most of the analytical operations of the CMRR. Construction will begin first on the RLUOB facilities, followed by construction of the CAT I facility. A full overview of the CMRR project can be found within: *Final Environmental Impact Statement for the Chemistry and Metallurgy Research Building Replacement Project at Los Alamos National Laboratory, Los Alamos, New Mexico, DOE/EIS-0350, November 2003.* This document is available to the public at http://www.eh.doe.gov/nepa/eis/eis_toc.html.

Air Emission Sources

The primary source of air emissions associated with the CMRR will be a maximum of five (5) dual fuel boilers located within the UB. Each boiler will have a maximum heat input rating of 11 MMBtu/hr. The boilers will be forced-draft, water tube design and produce hot water only (not steam or electricity). The units will be packaged and factory-assembled by the vendor for delivery to LANL. Natural gas will be the primary boiler fuel, with distillate fuel oil specified as a standby fuel in case of disruption to the natural gas supply. Each boiler will be equipped with a low NOx burner to control NOx emissions.

A metallographic sample preparation operation will be located within the CAT I building. Samples which contain beryllium will be processed for analysis using cutting, grinding, and polishing techniques. These operations are conducted under a lubricating bath within a glove box. All machined beryllium which may become airborne passes through the glove box ventilation system which is controlled by a HEPA filter. Exhaust gases are further controlled by a HEPA filter bank with three filters. Each HEPA filter has a minimum removal efficiency of 99.95%.

Small quantities of chemicals will be used within the CMRR laboratory operations. Chemical usage will be approximately equal to current usage at the existing CMR Building. Air pollutants emitted can be characterized as volatile organic compounds (VOC) or hazardous air pollutants (HAP). LANL currently tracks and reports to NMED chemical usage on a facility-wide basis. VOC and HAP emissions from the CMRR will be included in these reports.

In case of power disruption, the CMRR will utilize standby diesel generators to provide emergency power to critical systems. There will be five generators ranging in power output from 0.5 to 1.25 MW. These units qualify as exempt from air permitting and are listed as such in this application.

Attachment H

PSD Applicability Determination

Attachment H
PSD Applicability Determination

NMED implements the federal Prevention of Significant Deterioration (PSD) permit program under 20.2.74 NMAC. The PSD requirements apply to new major stationary sources or new projects defined as major modifications. The PSD program is intended to limit new air emissions in areas which are already in attainment of National Ambient Air Quality Standards (NAAQS) and also provide special protection for designated Class I areas.

The initial Title V operating permit for LANL was issued by NMED in April 2004. As requested by LANL, the permit contains enforceable facility-wide limits which serve to define the Laboratory as a minor stationary source for PSD purposes. This means modifications to LANL, such as the CMRR Replacement Project, cannot be a *major modification* as defined by 20.2.74 NMAC and subject to the PSD permitting. In order to trigger PSD review at a minor stationary source, a modification would in and of itself have to meet the definition of *major stationary source*. The thresholds which define a *major stationary source* are potential emissions equal to or greater than 250 tons per year of a regulated pollutant (or 100 tons per year if the source is a type listed in Table 1 of 20.2.74 NMAC). The highest maximum potential emission rate for a regulated pollutant from the CMR Replacement Project is CO at 24.9 tons per year. Therefore, the PSD permit requirements do not apply to this modification at LANL.

Attachment I

Regulatory Applicability and Compliance

Attachment I
Regulatory Applicability and Compliance

20.2.3 NMAC – Ambient Air Quality Standards
The simultaneous operation at maximum permitted capacity of all Chemistry and Metallurgy Research Replacement Facility (CMRR) boilers will not cause or contribute to an exceedance of any National or New Mexico Ambient Air Quality Standard. Air quality dispersion modeling was conducted using the higher emission rate by pollutant when comparing natural gas to fuel oil. Compliance was shown with all ambient standards. The dispersion modeling analysis is included in Attachment K to this application.

20.2.7 NMAC – Excess Emissions During Malfunction, Startup, Shutdown or Scheduled Maintenance
In the event of any startup, shutdown, or malfunction which results in excess emissions, LANL will comply with the notification requirements specified in Section 110 of this rule.

20.2.18 NMAC – Oil Burning Equipment – Particulate Matter
This regulation does not apply to the CMRR boilers. It applies to units with a rated heat input capacity greater than 250 MM Btu/hr.

20.2.33 NMAC – Gas Burning Equipment – Nitrogen Dioxide
This regulation applies to boilers with a heat input of greater than 1 million MMBtu per year per unit. The maximum annual input for each project boiler is 96,360 MMBtu per year (11 MMBtu/hr x 8,760 hr/yr). This regulation does not apply to the CMRR boilers.

20.2.34 NMAC – Oil Burning Equipment – Nitrogen Dioxide
This regulation also applies to boilers with a heat input of greater than 1 million MMBtu per year per unit. The maximum annual input for each project boiler is 96,360 MM Btu per year (11 MMBtu/hr x 8,760 hr/yr). This regulation does not apply to the CMRR boilers.

20.2.61 NMAC – Smoke and Visible Emissions
This regulation will be applicable to the CMRR boilers. The regulation limits visible emissions to less than 20% opacity. Based on observations, LANL has found that visible emissions from boilers burning natural gas are less than 20% opacity. The primary fuel for the boilers is natural gas, and the 20% opacity limit will be met.

20.2.70 NMAC – Operating Permits
LANL was issued a final Title V operating permit in April 2004. The conditions within the New Source Review (NSR) permit issued for this application will be incorporated into LANL's operating permit subsequent to issuance of the NSR permit. As required by 20.2.70 NMAC, LANL will submit to NMED a permit modification for the Title V permit no later than 12 months from commencing operation of the CMRR.

20.2.72 NMAC – Construction Permits
The submittal of this application fulfills the requirements of this regulation to obtain an NSR permit prior to the start of construction of a new or modified source.

20.2.73 NMAC – Notice of Intent and Emission Inventory Requirements
This application meets the requirements of this regulation to submit a Notice of Intent (NOI) for the proposed project. Estimated actual emissions from the permitted operations at the CMRR will be reported to NMED in the annual emissions inventory for LANL.

20.2.74 NMAC – Permits – Prevention of Significant Deterioration (PSD)
A PSD permit is not required for this project. See Attachment H of this application for a discussion of PSD applicability.

20.2.77 NMAC – New Source Performance Standards
This regulation adopts by reference the federal New Source Performance Standards (NSPS) at 40 CFR Part 60. Each project boiler will be subject to the NSPS at 40 CFR Part 60, Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units. Subpart Dc applies to boilers that have a maximum design heat input capacity of greater than or equal to 10 MMBtu/hr and less than or equal to 100 MMBtu/hr. Subpart Dc applies to each new boiler within this size range regardless of the type of fuel burned. The requirements within Subpart Dc vary according to the boiler size and type of fuel burned, with more stringent requirements for larger units or those burning fuels with higher emission rates.

For the primary fuel to be used at the CMRR, natural gas, Subpart Dc does not specify any emission limits. The only requirement specified is at 60.48c (g) to monitor and record daily the amount of fuel combusted. When the standby fuel distillate fuel oil is burned, a sulfur dioxide standard applies. As provided at 60.42c (d), the standard is a fuel oil sulfur limit of no greater than 0.5% sulfur. Compliance with the fuel oil sulfur limit will be determined by a certification from the fuel supplier as allowed under 60.42c (h) (1). The particulate matter standard at 60.43c does not apply to these units.

EPA has routinely approved alternate monitoring plans for gas-fired boilers with fuel oil as a standby fuel. NMED has previously approved this type of alternate plan for two boilers at LANL's TA-55 subject to Subpart Dc. The alternate plan is recording natural gas usage monthly instead of daily. If fuel oil is used, the usage will be recorded daily. LANL is requesting approval of this alternate plan (see cover letter to this application).

As required by Subpart Dc, LANL will also comply with the reporting and recordkeeping requirements applicable to the use of distillate fuel oil. Records of fuel supplier certification will be kept as required by 60.48c (e) (11), and the required semiannual report under 60.48c (e) and 60.48c (j) will be submitted to NMED.

LANL will also meet the NSPS general provision requirements regarding notification of the date of construction and initial startup required at 60.7 (a) for the CMRR boilers.

20.2.78 NMAC – Emission Standards for Hazardous Air Pollutants
This regulation adopts by reference the federal National Emission Standards for Hazardous Air Pollutants (NESHAP) at 40 CFR Part 61. The metallographic sample preparation operation in the CAT I Building will be subject to the NESHAP at 40 CFR Part 61, Subpart C – National Emission Standard for Beryllium. Under this regulation, cutting or grinding of beryllium is considered machining or a *machine shop*. Regulated activities are subject to an emission standard at 61.32(a) of 10 grams beryllium per 24-hour period. An initial stack test for beryllium is also required at 61.33 within 90 days of startup. Notification of anticipated and actual startup of the activity is required by 61.09. LANL will comply with all applicable requirements of the beryllium NESHAP.

20.2.82 NMAC – Maximum Achievable Control Technology Standards for Source Categories of Hazardous Air Pollutants
This regulation adopts by reference the federal Maximum Achievable Control Technology (MACT) standards at 40 CFR Part 63. There are no MACT standards which would apply to the project.

40 CFR Part 61, Subpart H – NESHAP for Radionuclides other than Radon from DOE Facilities
The CMRR will also be subject to the NESHAP at 40 CFR Part 61, Subpart H – NESHAP for Radionuclides other than Radon from DOE Facilities. NMED has not adopted this regulation, which is enforced by the U.S. EPA in New Mexico. LANL will obtain U.S. EPA preconstruction approval for the CMRR, and comply with the emission standard and monitoring requirements of this regulation.

Attachment J

Operational Plan for Startup, Shutdown, or Malfunction

Attachment J
Operational Plan for Startup, Shutdown, or Malfunction

The Chemistry and Metallurgy Research Replacement Facility (CMRR) will be operated under a series of operating procedures to ensure protection of employee safety and health and the environment. The most current operating procedures will be available for review upon request. In addition, for the Utility Building boilers, a factory-authorized service representative will provide boiler start-up service and training to LANL maintenance personnel with respect to adjusting, operating, and maintaining the boilers.

Attachment K

Dispersion Modeling

Attachment K

Air Dispersion Analysis – CMRR Utility Building Boiler Stack

Narrative summary of the proposed construction, modification, or revision.

This report is a summary of the air dispersion analysis performed by LANL's Meteorology and Air Quality (MAQ) group to determine the ambient air quality impact with respect to National and New Mexico Ambient Air Quality Standards (NAAQS and NMAAQS) from the Chemistry and Metallurgy Research Replacement (CMRR) facility Utility Building boilers. This analysis determined the radius of impact (ROI) of the CMRR boiler stack emissions and, where warranted, the cumulative impact of all significant LANL sources for criteria pollutants whose ROI analyses reveal a significant impact. Construction on this new facility is scheduled to begin in 2005. The emissions presented in this report are conservative estimates of potential emissions based on current design plans.

List of file names of the model input, output, and other files used.

The following Table 1 lists the file names of the files used in this analysis.

Table 1. File Names for ISCST3 Modeling

Filename	Description
CMRR_N01.inp CMRR_N01.out	Input and output files for ROI evaluation of NOx emissions from CMRR boiler stack.
CMRR_SO1.inp CMRR_SO1.out	Input and output files for ROI evaluation of SOx emission from CMRR boiler stack.
CMRRcNO2.inp CMRRcNO2.out	Input and output files for evaluation of the cumulative impact of NOx from CMRR boiler stack and all significant LANL sources.
CMRRcSO2.inp CMRRcSO2.out	Input and output files for evaluation of the cumulative impact of SOx from CMRR boiler stack and all significant LANL sources.
LOSAL95.met	The meteorological data file used in the modeling analysis.
Agua Fria, Bland, Canada, Cochiti Dam, Espanola, Frijoles, Guaje Mountain, Horcado Ranch, Montosa Peak, Puje, Valle Toledo, White Rock	United States Geological Survey (USGS) digital elevation model (DEM) file used to supply terrain heights for sources, some receptors, and buildings included in the model analysis.
Discrete Receptor Coordinates	LANL generated data files for public roads within LANL and other receptor locations along the LANL boundary.

Discussion of the modeling approach and justification, model options, and types of analysis.

The 2003 version of the "New Mexico Air Quality Bureau – Dispersion Modeling Guidelines" (NMAQB Guidance) was reviewed prior to this analysis. In addition to the procedures and requirements provided in the NMAQB Guidelines, the procedures given in the EPA's Guideline on Air Quality Models (40 CFR 51, Appendix W) were followed.

Models used and their justification.

The ISCST3 model was used in the dispersion analysis. LANL also employed a graphical user interface to the ISC model produced by Lakes Environmental to more effectively implement the ISCST3 model. There were two main model runs, one for ROI analyses and one for analyses of cumulative impacts of all significant LANL sources and comparison to NMAAQS & NAAQS.

Model Options and their justification

The following modeling options were used in the dispersion analysis:

- Under source type options, LANL selected and used the type POINT. LANL used the current best estimates for the stack parameters; the actual values for the exhaust stack may differ once construction begins on the facility.

- MSGPRO—The NMAQB Guideline recommends selecting this option when using meteorological data from the Bureau's archive. This option allows the ISCST3 model to continue running in the event missing data is encountered in the meteorological data file. With this option selected, ISCST3 treats missing data similarly to "calms". Although this option was selected, examination of the meteorological data file did not reveal any missing data.

- HE>ZI—This option addresses the potential problem that occurs when the receptor elevation is lower than stack base elevation, which can occur at Los Alamos due to the terrain complexity. In this situation, the mixing layer height (ZI), which is terrain following, may be lower than the effective plume height (HE), which is horizontal. This affects the plume "reflection" calculation in ISCST3, leading to erroneously large concentrations. By selecting this option, the model limits the plume centerline height to be less than the mixing layer height, resulting in realistic concentrations.

- The conservative "simple and complex" terrain option is selected by omitting the NOSMPL and NOCMPL keywords on the model option control pathway. Using this method allows ISCST3 to implement both simple (receptor height below stack height) and complex (receptor height above plume height) terrain algorithms when calculating concentrations. For intermediate terrain (receptor

height between stack height and plume height), ISCST3 will calculate concentrations using both simple and complex terrain algorithms, and the higher of the two concentrations is selected.

A discussion of the met-data including identification of the source.

One year of meteorological data was supplied from an on-site met tower located at TA-6. The distance from the tower to the release site is about 1.5 km. The file consists of hourly surface data from the LANL met-tower and mixing height data from Albuquerque International Airport. MAQ used 1995 meteorological data, because it is the most recent annual data set quality assured and formatted for model input by NMED. LANL does have on-going meteorological measurements, but a more recent annual data set would not equate to a better data set or change the model results in any appreciable way.

USGS map showing the location of the facility.

Attachment E to the permit application shows a copy of a 7.5 minute USGS topographical map with the location of the new Utility Building.

A description of the site, building dimensions and a plot plan.

Description of the site.

The proposed new CMRR utility building will be constructed at TA-55, near Pajarito Road and Pecos Drive.

All criteria pollutants emitted by the source.

The criteria pollutants emitted by the source are nitrogen oxides (NOx), sulfur oxides (SOx), carbon monoxide (CO), and particulate matter (TSP and PM_{10}). Table 2 provides the emission rates for the pollutants included in the modeling analyses. Attachment C – Emission Calculations of this application provides a complete description of the basis for these emission rates.

Table 2. Pollutant emission rates from the new boiler stack for the CMRR Utility Building used in the dispersion modeling analysis, given in grams per second.

Source ID	NOx	CO	SOx	PM_{10}	TSP
CMRRSTK1	1.01	0.69	3.64	0.12	0.17

The averaging time for each regulated pollutant.

The averaging times used in the modeling were 1-hour, 3-hours, 8-hours, 24-hours, and annual.

If modeled stack parameters differ from those listed in the report, explain why.

Since architectural plans for the CMRR Utility Building are not yet finalized, a number of assumptions were made in regards to the stack parameters. The stack height used in the modeling is set to 8 feet above the constructed height of the Utility Building, which is currently estimated to be 25 feet tall. The stack diameter is estimated to be 2.5 feet. The stack effluent temperature and exhaust rate are based on conservative, i.e. lower, values provided by a potential vendor for the low fire boiler operating condition. Actual temperature and exhaust rate are anticipated to be higher.

Modeling Results

A discussion of the radius of impact determination

MAQ used the combination 1000 m/500 m/LANL-boundary grid discussed above to determine the radius of impact (ROI) for each pollutant emitted from the CMRR boiler-stack. The resulting concentration for NOx exceeded the significance level for the 24-hour averaging period (significance level = 5 $\mu g/m^3$). The resulting radius of impact is about 1.5 km.

The resulting concentration for SOx exceeded the significance level for the 3-hour, 24-hour, and annual averaging period (significance level = 25, 5, and 1 $\mu g/m^3$). Attachment 1 to this report shows the results of the model output for the 3-hour SOx modeling analysis for ROI. The radius of impact is about 17 km and was the largest ROI in the SOx analysis.

The results of the modeling analysis are summarized in Table 3. The 24-hour (annual) NOx value was multiplied by 0.4 (0.75) to estimate NO_2. The NOx and SOx concentrations reached significant levels offsite and are shown in bold in Table 3.

Table 3. Highest impact of emissions from CMRR boiler stack and (significance levels).

	NO_2	**SO_2**	**CO**	**PM_{10}**	**TSP**
	$\mu g/m^3$	**$\mu g/m^3$**	**$\mu g/m^3$**	**$\mu g/m^3$**	**$\mu g/m^3$**
1-hour maximum average			99 (2000)		
3-hour maximum average		**174** (25)			
8-hour maximum average			17 (500)		
24-hour maximum average	**5.6** (5)	**50** (5)		1.7 (5)	2.3 (5)
Annual Geometric Mean					0.15 (1)
Annual Arithmetic Mean	0.2 (1)	**3.7** (1)		0.11 (1)	

The maximum 24-hour and annual TSP and PM_{10} concentrations calculated with ISC did not exceed the significance levels given by NMAQB Guidelines anywhere offsite. Nor did the maximum annual NOx concentration or maximum 1-hour and 8-hour CO concentrations exceed significance levels. This demonstrated compliance with NAAQS and NMAAQS for these pollutants and averaging times, and further analysis is not required.

The 24-hour NOx and the 3-hour, 24-hour, and annual SOx emissions from the new boiler stack for the CMRR utility building had a significant impact. Therefore, to determine the cumulative impact from other significant sources of NOx and SOx emissions at LANL, those significant sources were modeled in addition to the CMRR stack emissions. A list of the sources used in the cumulative analysis is provided as Attachment 2 to this report.

The results from this cumulative impacts analysis are provided in Table 4. As shown, maximum impacts from the CMRR boilers combined with all significant LANL sources do not exceed applicable NAAQS or NMAAQS.

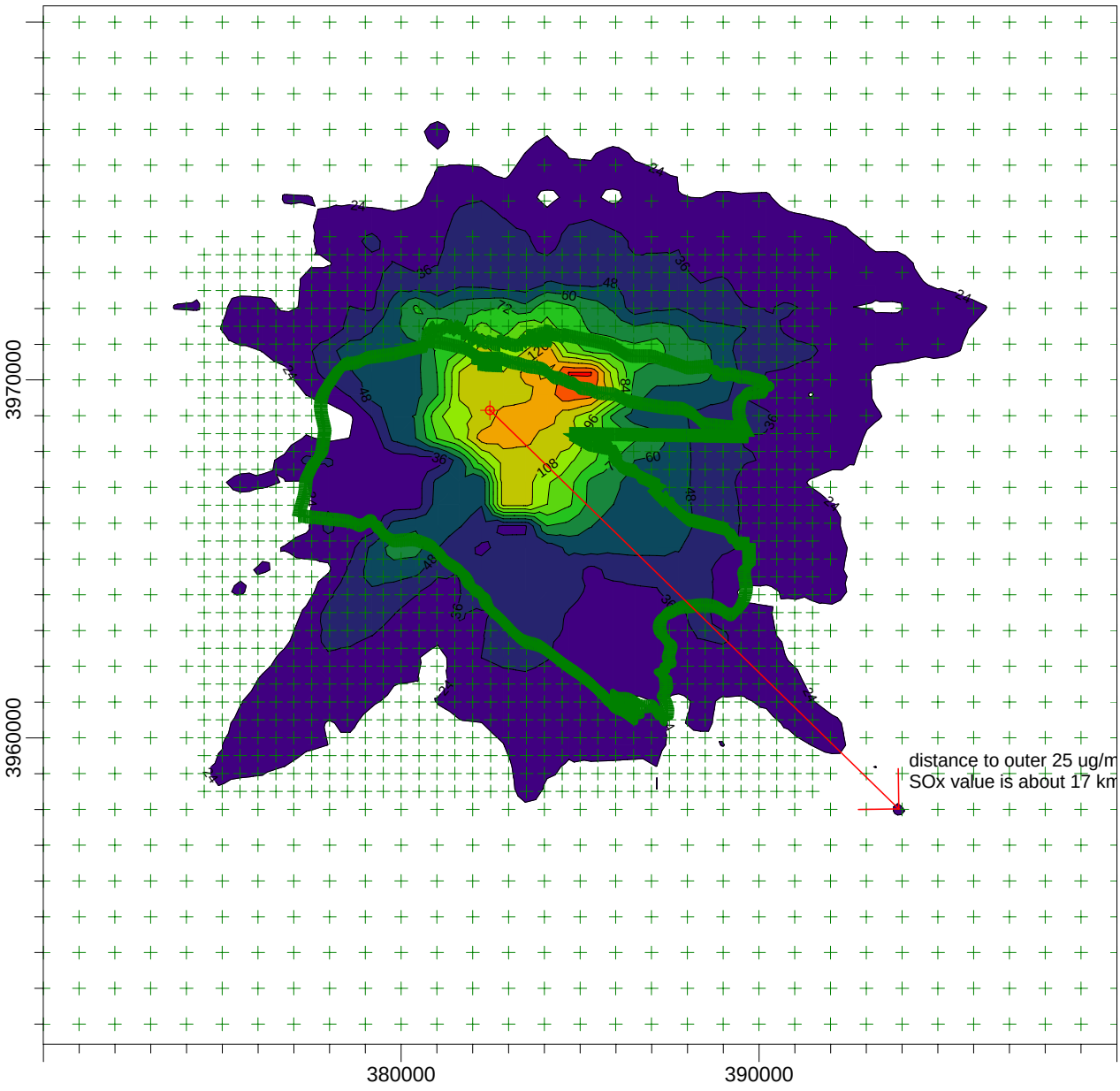
Table 4. ISCST3 modeling results for cumulative impact of LANL NOx and SOx sources including estimated emissions for the new CMRR Utility Building. Standards are in parentheses.

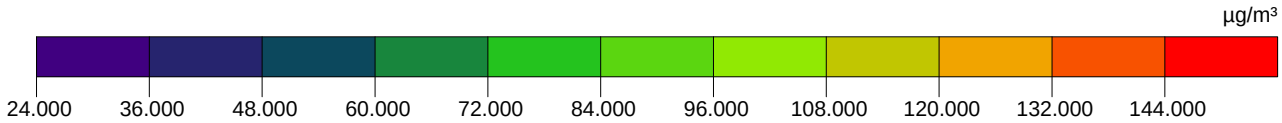
	NO_2 maximum Off-site concentration	**SO_2** maximum Off-site concentration
Averaging Period	**µg/m^3**	**µg/m^3**
3-hour-maximum result	Na	388 (1045)
24-hour-maximum result	34.3 (150)	91.4 (210)
Annual Arithmetic Mean	4.1 (75)	10.7 (42)

The location of the highest offsite impacts for the short term averaging periods (3 hours and 24 hours) is a residential area of Los Alamos located about 1.7 km from the main power plant at TA-3. The location of the highest offsite impact for the annual average concentrations is along the LANL/DOE property line with the Los Alamos County airport.

PROJECT TITLE:

Attachment 1 to Air Dispersion Analysis - CMRR Utility Building
Plot File of 1st Highest 3-hr SOx Values





MODELING OPTIONS: **CONC, RURAL, FLAT, MSGPRO, NOCMPL, HE>ZI**			COMPANY NAME:	
OUTPUT TYPE: **CONC**	RECEPTORS: **4367**	COMMENTS: ROI analysis for SOx emission from CMRR utility building, the largest ROI occured for the 3-hour averaging period	MODELER:Johnson and Jacobson	SCALE: 0 5 km
MAX: **174.13361**	UNITS: **µg/m³**		DATE: **2/25/2005**	PROJECT NO.: **CMRRSTK1**

Attachment 2 to Air Dispersion Analysis - CMRR Utility Building Boiler Stack

A list of sources and their ISCST3 identification as used in the cumulative modeling analysis.

	Descriptive Name	ISCST3-ID	note
1	Power Plant, 1st Exhaust Stack	TA3_22_1	
2	Power Plant, 2nd Exhaust Stack	TA3_22_2	
	Air Curtain Destructor - Trench	TA16ACD1	1
	Air Curtain Destructor - Trench	TA16ACD2	1
	Air Curtain Destructor - BOX	TA16ACD3	1
3	TA-33 Diesel Generator	TA33_DG1	
4	TA-21-357 Boilers (3)	TA21_B3	
	TA-21 Rock Crusher	TA21_RC1	1
5	TA-60 Asphalt Plant	TA60_AP1	
6	TA-59-1 Boilers (2)	TA59_B2	
7	TA-55-6 Boilers (2)	TA55_B2	
8	TA-53-385 Boilers (2)	TA53_B2	
9	TA-50-2 Boiler	TA50_B1	
10	TA-48-1 Boilers (3)	TA48_B3	
11	TA-16-1484 Boilers (2)	1484_B2	
12	TA-16-1485 Boilers (2)	1485_B2	
	TA3-38 Carpenter Shop	TA3_38C	2
	TA15-563 Carpenter Shop	T15_563C	2
	TA52-11 Data Disintegrator	TA52_PS	2
13	TA-3 Combustion Turbine	TURBINE	
14	TA36 Sled Track open burn	TA36OB	
15	TA-11 Drop Tower open burns	TA11OB	
16	TA-16 Flash Pad	TA16OB	
17	TA55 CMR-R Facility Boilers (5)	CMRRSTK1	

notes:

1 These sources are no longer in operation.

2 These sources have particulate matter emissions only.